June 29, 2015

Ms. Kirstin Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: **Hydro Ottawa Limited Custom Incentive Regulation ("Custom IR")**
Application for 2016-2020 Electricity Distribution Rates and Charges - Revisions
Board File Number EB-2015-0004

1. Please find enclosed evidentiary updates to Hydro Ottawa's 2016-2020 Custom Incentive Regulation Distribution Rate Application as originally filed with the Board April 29, 2015.

2. The enclosed evidentiary revisions are largely administrative in nature with the majority of updates consisting of revisions to historical financial data to replace or supplement the 2014 forecasted data with the 2014 year end actuals. Hydro Ottawa confirms that the updated evidence does not have a material impact on the Application or the relief requested therein. For clarity the enclosed evidentiary updates include:

• Numerical updates to replace or supplement 2014 forecasted year end results with 2014 year end actuals, including compensation and headcount;

• A copy of Hydro Ottawa Limited Audited Financial Statements

• Minor corrections to numbers provided in the Executive Summary

• A copy of Hydro Ottawa's approved Conservation and Demand Management 2015-2020 plan

3. Pursuant to Rule 11.03 of the Board's Rules of Practice and Procedure, as revised, revisions are denoted in red and are provided on coloured (pink) paper that indicate the date of the revision. In addition, Hydro Ottawa is providing a table (Appendix A) describing the original evidence, each revision to the evidence, whether the change was numerical and the difference between the original and revised evidence.

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4. Text-searchable electronic copies of this submission are being provided to all registered interveners and a copy will be posted and available for public review on Hydro Ottawa's website. Finally, seven (7) paper copies of the evidentiary updates will be forwarded to the Board.

Please do not hesitate to contact me should you have any questions.

Respectfully,

Geoff Simpson
Chief Financial Officer
Hydro Ottawa Holding Inc.
3025 Albion Road North, PO Box 8700
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C.C. Christie Clark, OEB
Fred Cass (Aird & Berlis)
EB-2015-0004 Interveners

Appendix A

Table of Revisions

Hydro Ottawa Limited 2016-2020 Custom IR Application (EB-2015-0004)

Exhibit	Tab	Schedule	Appendix	June 26, 2015 Revised/Updated Content	Description of Revision/Updates
A	**2**	**1**		Corrected percent of workforce eligible to retire and date by which they are eligible to retire	**Original**: ~~43%~~, ~~2020~~ → **Corrected**: 44%, 2023
				Corrected 2006-2009 average annual net and gross expenditures	**Original**: ~~$60 M~~ Net, ~~$75 M~~ Gross → **Corrected**: $67 M Net, $89 M Gross
				Capital Expenditure under IRM	Removed first line on page 11
				OM&A by Cost Driver	Table 9 updated to reflect 2014 Actuals
				Bill Impacts	Minor corrections made to the % increase to total bill line to align with Exhibit H-12-1
A	**4**	**1**		Audited Financial Statements	Updated to reflect 2014 Actuals
			Attachment A-4(B)		Updated to reflect 2014 Actuals
A	**4**	**2**		Reconciliation of Audited Financial Statements	Updated to reflect 2014 Actuals
			Attachment A-4(H)		Updated to reflect 2014 Actuals
A	**4**	**3**		Annual Report and Management Discussion	Updated to reflect 2014 Actuals
			Attachment A-4(I)		Updated to reflect 2014 Actuals
A	**6**	**3**		Table of Contents	To reflect updates and corrections

Exhibit	Tab	Schedule	Appendix	June 26, 2015 Revised/Updated Content	Description of Revision/Updates
B	**1**	**1**		Rate Base	Updated to reflect 2014 Actuals
B	**1**	**2**		Hydro Ottawa Distribution System Plan	Tables 3.4.1, 3.4.3, 3.4.5, 3.4.7, 3.5.1 updated to reflect 2014 actuals
B	**2**	**1**		Assets –Continuity Schedule	Updated to reflect 2014 Actuals
			Appendix 2-BA		Updated to reflect 2014 Actuals
B	**3**	**1**		Working Capital Requirement	Updated to reflect 2014 Actuals
B	**5**	**1**	**Appendix 2-AA**		Updated to reflect 2014 Actuals
			Appendix 2-AB		Updated to reflect 2014 Actuals
B	**5**	**3**	**Appendix 2-D**		Updated to reflect 2014 Actuals
C	**1**	**1**		Load Forecast	Updated to reflect 2014 Actuals
C	**1**	**2**		Accuracy of Load Forecast and Variance Analysis	Updated to reflect 2014 Actuals
			Appendix 2-IA		Updated to reflect 2014 Actuals
			Attachment C-1(B)		Updated to reflect 2014 Actuals
C	**2**	**1**		Updated Other Revenue to reflect 2014 Actual Updated Affiliate Services Revenue to reflect 2014 Actual	Table 1 updated to reflect 2014 actuals; added variance explanations Table 2 updated to reflect 2014 actuals
			Appendix 2-H		Updated to reflect 2014 Actuals
C	**2**	**2**		Updated Service Charge Revenue to reflect 2014 Actual	Table 1 updated to reflect 2014 actuals; added 2015 Forecast
D	**1**	**1**		Updated Summary of Total Operating Expenses	Table 1 updated to reflect 2014 actuals

Exhibit	Tab	Schedule	Appendix	June 26, 2015 Revised/Updated Content	Description of Revision/Updates
D	**1**	**2**		Updated OM&A Overview	Tables 1-3 updated to reflect 2014 actuals
			Appendix 2-JA		Updated to reflect 2014 Actuals
			Appendix 2-L		Updated to reflect 2014 Actuals
D	**1**	**3**		OM&A Cost Drivers and Program Variance Analysis	Tables 1-11 updated to reflect 2014 actuals
			Appendix 2-JB		Updated to reflect 2014 Actuals
			Appendix 2-JC		Updated to reflect 2014 Actuals
D	**1**	**4**	**Attachment D-1(C)**	Hydro Ottawa Corporate Productivity Scorecard	Updated to provide audited 2014 scorecard
D	**1**	**6**		Customer Service Strategy	Updated document to incorporate the planning concept of a single-integrated whole of company roadmap; removed foundational customer experience components in the original Table 1, currently Table 2
D	**1**	**7**		Workforce Planning Strategy	Tables 1-2 updated to reflect 2014 actual hires
D	**1**	**8**		Employee Compensation Strategy	Tables 2-5 updated to reflect 2014 actuals
			Appendix 2-K		Updated to reflect 2014 Actuals
D	**1**	**10**		Hydro Ottawa approved 2015-2020 CDM Plan	Added
			Attachment D-1(G)		Added
D	**2**	**1**		Shared Corporate Services Provided by Hydro Ottawa Shared Corporate Services Received by Hydro Ottawa 2016 Test Year versus 2014 Actual Revenues from Affiliates Included in Other Revenue	Table 4 updated to reflect 2014 actuals Table 5 updated to reflect 2014 actuals Table 7 updated to reflect 2014 actuals; added variance explanation Table 8 updated to reflect 2014 actuals
			Appendix 2-N		Updated to reflect 2014 Actuals

Exhibit	Tab	Schedule	Appendix	June 26, 2015 Revised/Updated Content	Description of Revision/Updates
D	**2**	**4**		Regulatory Costs	Table 1 - Updated to reflect 2014 actuals
			Appendix 2-M		Updated to reflect actual amounts for 2014 and Annual % Change
D	**2**	**6**		Charitable and Political Donations	Updated Table 1 – Updated to reflect 2014 actuals
D	**3**	**1**		Depreciation Amortization Disposal	Updated to reflect 2014 Actuals
H	**9**	**1**		Loss Adjustment Factors	Updated to reflect 2014 Actuals
			Appendix 2-R Loss Factors		Updated to reflect 2014 Actuals
I	**1**	**1**		Current Deferral and Variance Accounts	Updated Table 3 with Q3 2015 Prescribed Interest Rates; Updated Table 5 & 6 with 2014 Actuals
I	**1**	**4**		One Time Incremental IFRS Costs	Updated Section 6 - Updated to reflect 2014 Actuals
			Appendix 2-U		Updated to reflect 2014 Actuals

MANAGEMENT DISCUSSION & EXECUTIVE SUMMARY

1.0 INTRODUCTION

This schedule provides a summary of Hydro Ottawa Limited (" Hydro Ottawa or HOL or the Company", "the utility")'s Custom Incentive Regulation ("Custom IR") rate application for the five year period beginning 2016 and ending in 2020. This schedule describes Hydro Ottawa's business plan and identifies the funding the company requires in order to continue to serve its current and future customers in a manner that allows it to fulfil its mission to deliver safe, reliable, affordable and sustainable electricity to the homes and businesses in the City of Ottawa and the Village of Casselman and to meet the demands of a growing, expansive and complex urban/rural environment while pursuing productivity improvements to benefit the company's ratepayers and an appropriate rate of return for its shareholders. This Executive Summary is guided by the requirements set out in Sections 2.4.1 and 2.4.2 of Chapter 2 of the Ontario Energy Board ("the OEB" or "the Board")'s Filing Requirements for Electricity Distributors Companies' Cost of Service Rate Applications, based on the forward Test Years (the 'Chapter 2 Requirements').

This application represents Hydro Ottawa's assessment of its capital and operational needs and of its commitment to its customers over the next five years. The investments set out in this application are required in order to address the pressures of aging infrastructure, a continuously growing customer base, challenging weather, increasing urban and rural development and modernization, an aging workforce, and a growing customer appetite for innovative leading-edge and technology-based services. Hydro Ottawa's challenge is to finance its operations so that it may continue to provide its customers with a safe and reliable source of electricity, as well as, acceptable customer service levels at reasonable rates.

By way of this application, Hydro Ottawa seeks approval for its five year Custom IR rate application which is based on a rate-setting model wherein Hydro Ottawa's capital

requirements are recovered on a five year forecasted cost of service basis and its operations, maintenance and administrative ("OM&A") requirements are recovered pursuant to an "I-X" formula. Hydro Ottawa seeks approval for final rates for a three year period beginning 2016 and ending 2018 and for its five year forecasted capital requirements. Hydro Ottawa proposes to apply to the Board to adjust its 2019 and 2020 rates to incorporate a revised inflation factor and updated cost of capital parameters. Finally, Hydro Ottawa reserves the right to file Y and Z factor applications during the course of its Custom IR period and proposes to share earnings with its customers based on increasing proportionality scale for earnings that rise above certain thresholds.

Recognizing its significant multi-year capital needs Hydro Ottawa has exercised the option provided to it pursuant to the Report of the Board entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (the "RRFE") to account for its unique capital funding requirements that cannot be accommodated for under the OEB's 4th Generation Incentive Regulation model. In filing a Custom IR application, Hydro Ottawa has applied the key tenants of the RRFE including, but not limited to;

a) By applying for an initial rebasing (financial viability) then applying for a rate setting approach to recover forecasted capital needs but recovers OM&A needs pursuant to an I-X formula (operational effectiveness);
b) By identifying historical and future productivity initiatives to achieve continuous improvement (operational effectiveness);
c) By providing a total cost and reliability econometric benchmarking, as authored by Power System Engineering and based on the OEB's benchmarking approach;
d) By providing a customer engagement strategy to ensure responsiveness to identified customer preferences (customer focus);
e) By providing a comprehensive asset management and infrastructure investment plan that is linked to the capital budget, prioritizes for total bill

impact, is informed by customer consultation and been subject to an independent assessment;

f) By providing an annual reporting mechanism through which Hydro Ottawa can inform the Board of its progress on implementing its capital plan as well as its continuous improvement initiatives.

This application has been prepared and guided by the OEB's requirements set out in the OEB's Filing Requirements for Electricity Distributors Companies' Cost of Service Rate Applications and seeks to align with the OEB's guidance to electricity distributors in its' Renewed Regulatory Framework for Electricity Distributors report ("RRFE"). For further details illustrating how the evidence comprising Hydro Ottawa's application aligns with the Board's RRFE expectations please see section 3.0 below and refer to Exhibit A-2-2.

2.0 ABOUT HYDRO OTTAWA

2.1 General Facts

Hydro Ottawa serves Canada's capital Ottawa and the Village of Cassleman. Ottawa is home to the Parliament of Canada and key departments within the federal public service, is the second largest city in Ontario and the 6th largest city in Canada. Hydro Ottawa is the fourth largest electricity distributor in Ontario serving over 315,000[1] customers and has a service territory of 1,104 square kilometers that includes a complex dense urban core, large areas of suburban development and a vast rural area representing approximately 60%[2] of the company's territory. Hydro Ottawa is the amalgamation of five predecessor utilities: Ottawa Hydro, Kanata Hydro, Gloucester Hydro, Nepean Hydro and Goulbourn Hydro. In 2002, Hydro Ottawa acquired the service territory of Casselman Hydro.

[1] New customer growth is occurring at a rate of approximately 1% per annum.
[2] According to the latest Ontario Energy Board ("OEB" or "Board") Electricity Distributor Yearbook results (2013), Hydro Ottawa has a total service area of 1,104 square kilometers with approximately 60% of the service territory being classified as rural.

2.2 Challenges faced by Hydro Ottawa

Hydro Ottawa operates in a unique market with unique challenges. Among the challenges unique to Hydro Ottawa is its weather. Ottawa winters are cold and they are long. Relative to other large local distribution companies ("LDCs") in Ontario, Hydro Ottawa must contend with longer periods of ground freeze and more significant snow cover. This impacts Hydro Ottawa's operations and its costs in a number of significant ways. First, extended periods of ground freeze and snow cover shortens the infrastructure construction period and lengthens the moratorium period by approximately 4-6 weeks which can reduce the construction seasons by as much as 20%. In addition, snow and ice impedes normal work flow because it increases time to access sites, access equipment safely, and impacts the set-up/take down of a work area. The increase to time spent at each worksite reduces the number of worksites that can be scheduled in a day consequently increasing overall costs from a unit of work perspective. On the capital side, Ottawa's long winters require the municipality to use significant quantities of road salt which has a corrosive effect on ductwork, wires and insulators shortening the effective asset life of Hydro Ottawa assets.

Another challenge that Hydro Ottawa faces stems from the approximately ~~43%~~ 44% of its workforce that is eligible to retire by ~~2020~~ 2023. ~~or during the course of Hydro Ottawa's Custom IR rate period~~. The preponderance of employees eligible to retire are technical and operational staff that require multi-year training and apprenticeship. Details on the measures Hydro Ottawa is undertaking to address the challenges of managing the utility with an aging workforce are set out in its Workforce Planning Strategy available in Exhibit D-1-7.

Like other LDCs, Hydro Ottawa also faces challenges presented by aging infrastructure. Hydro Ottawa estimates that approximately 30% of its assets have reached or exceeded their expected useful life. This is creating increasing pressure on the company to replace aging assets before they fail. See Exhibit B-1-2(A)-(C) for further details. Also, though serving a major urban centre, Hydro Ottawa must contend with intensification of development within its urban core as well as continued suburban growth in the east,

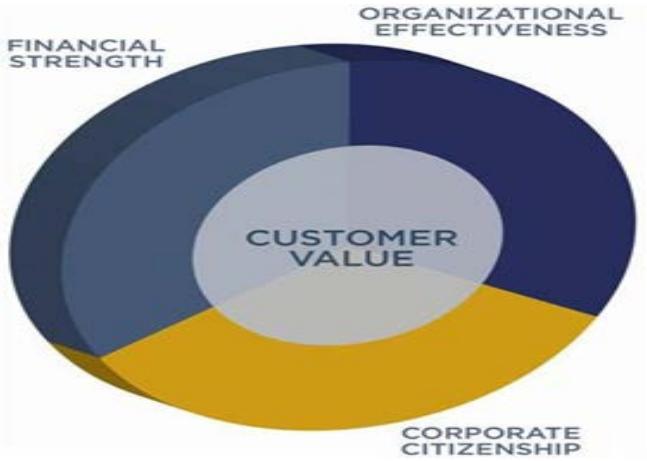
west and southern regions of its service territory. One of the challenges that is unique to Hydro Ottawa to execute its capital construction plans arises from constraints on contractor availability. Despite the City of Ottawa being the second largest city in Ontario, there are an insufficient number of qualified contractors to support Hydro Ottawa's capital plans requiring Hydro Ottawa to pay a premium in order to attract contractors from the Toronto region.

Finally, with raising electricity rates comes rising customer expectations. Hydro Ottawa's customers are expecting new and/or improve services allowing the customer to interface with Hydro Ottawa and obtain information (i.e., billing, time-of-use consumption, appliance consumption, outage alerts, etc.,) on the device or medium of the customers' choice and at a time of the customers' choice. The challenge moving forward is to meet these expectations in an innovative, agile and timely manner within the funding resources provided for and approved by the Board in this application. Hydro Ottawa's ability to be innovative and agile and its ability to respond to industry market changes and customer expectations will become an increasingly important strength over the next five years with the introduction of new technologies, and as legislative and policy modernization take a foothold within the industry to incentivize distributor consolidation.

2.3 Hydro Ottawa Four Strategic Objectives

Hydro Ottawa's four strategic objectives are: a) to deliver customer value; b) to create sustainable growth; c) to achieve performance excellence; d) to contribute to the well-being of the community. As denoted in Figure 1 below, Hydro Ottawa fundamentally believes that delivering customer value is at the core of its mission and that if it can create sustainable growth, achieve performance and contribute to our community, the customer will derive long term value from the company and the activities and initiatives it proposes undertake over the next several years.

Figure 1:



These corporate objectives are consistent with the four performance outcomes set out in the RRFE namely that a) Customer Focus – that services are provided in a manner that responds to identified customer preferences; b) Operational Effectiveness – continuous improvement in productivity and cost performance is achieved and utilities deliver on system reliability and quality objectives; c) Public Policy Responsiveness – that utilities deliver on obligations mandated by government and d) Financial Performance – financial viability is maintained and savings from operational efficiencies are sustainable.

3.0 ALIGNMENT WITH THE RRFE

The design of Hydro Ottawa's Custom IR application and the evidence filed in support of its capital and operational funding requirements seeks to respond to the Board's expectations for Custom IR applications as set out in the RRFE. These expectations and the evidence that Hydro Ottawa relies on to illustrate its compliance are summarized in Exhibit A-2-2 as well as in Table 1 below.

1 **Table 1.**

OEB's RRFE Performance Outcomes		Hydro Ottawa's Corporate Objectives		HOL Evidentiary Alignment with RRFE
Focus	**Objective**	**Focus**	**Objective**	
Customer Focus	Services are provided in a manner that responds to identified customer preferences	**Customer Value**	We will deliver value across the entire customer experience by providing reliable, responsive and innovative services at competitive rates	Exhibit D-1-6 Customer Service Strategy Exhibit A-3-1 – Customer Engagement Plan See Exhibit B-1-2 for HOL's Distribution System Plan.
Operational Effectiveness	continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;	**Organizational Effectiveness**	We will achieve performance excellence by cultivating a culture of innovation and continuous improvement	See Exhibit D-1-5 for an overview of productivity & benchmarking See Exhibit D-1-4 for a discussion of HOL's historical and forward looking productivity initiatives See Exhibit D-1-7 for Hydro Ottawa's Workforce Planning strategy See Exhibit B-1-2 for HOL's Distribution System Plan.
Financial Performance	Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Strength**	We will create sustainable growth in our business and our earnings by improving productivity and pursuing business growth opportunities that leverage our strengths — our core capabilities, our assets and our people	See Exhibit D-1-5 for an overview of Hydro Ottawa's productivity & benchmarking See Exhibit D-1-4 for a copy of Hydro Ottawa's OEB Scorecard. See Exhibit E for details of Hydro Ottawa Cost of Capital and Capital Structure. See Exhibit B-1-2 for HOL's Distribution System Plan.
Public Policy Responsiveness	utilities deliver on obligations mandated by government	**Corporate Citizenship**	We will contribute to the well-being of the community by acting at all times as a responsible and engaged corporate citizen	See Exhibit D-1-9 for details of Hydro Ottawa's Health, Safety & Environment Plan Hydro Ottawa will file at a later date its approved 2015-2020 CDM Plan See Exhibit B-1-2 for HOL's Distribution System Plan.

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4.0 HYDRO OTTAWA'S CUSTOM IR APPLICATION

4.1 Hydro Ottawa Guiding Principles

Hydro Ottawa proposes a Custom IR rate-setting framework that constrains operational funding increases after rebasing and provides the ability to recover its multi-year capital investments. To facilitate the development of the 2016 to 2020 Custom IR application Hydro Ottawa developed the following guiding principles:

- ✓ Ensure rate increases are as minimal as possible and that rates are timely and commensurate with the cost to provide service.
- ✓ Ensure new customer services can be introduced throughout the term of the plan so that customer expectations are met.
- ✓ Invest in assets which ensure that the distribution system is efficient and reliable in order to meet expectations of both existing customers and new customers during the five-year term.
- ✓ Demonstrate cost containment and control, encourage productivity initiatives, while still providing customers with appropriate service levels.
- ✓ Ensure that capital expenditures earn an appropriate rate of return in a timely manner so that continued investment in capital assets can be afforded and, therefore, meet customer expectation's regarding reliability.

4.2 Principle Drivers Justifying Custom IR

Hydro Ottawa's decision to adopt a Custom IR rate-setting model is justified in light of the significantly large multi-year capital investments needed by Hydro Ottawa to continue to provide a safe and reliable electricity distribution service so that it may continue to meet the needs and expectations of its customers. Hydro Ottawa's capital requirements are the result of investments identified through the Company's asset management planning and network investment planning processes and in particular through its Heath Indexing method used to assess the condition of its assets. A copy of Hydro Ottawa's Asset Management Planning process, its Distribution System Plan and its Grid Transformation Plan can all be found in Exhibit B-1-2.

4.3 Hydro Ottawa's Financial Planning and Budgeting Approach

Hydro Ottawa's approach to its 2016 Custom IR rate application and the financial planning considerations and budgeting were informed by and reflect the guiding principles enunciated above. Hydro Ottawa's financial planning and budgeting approach included a number of interrelated steps which started with the development of a detailed forecast of capital and operations, maintenance and administrative (OM&A) expenditures, for the years 2016 through 2020.

4.3.1 Capital Budget Forecasts

The final detailed forecast of capital expenditures for each year of 2016 through 2020 presented in this application is the result of a number of refinements and several iterations. Initial forecasts included funding requests that were greater than the final forecast, as there was opinion that a higher funding level was required from an asset-needs perspective. That higher funding level was measured against a number of other key factors including rate impacts and resources available and/or required for execution of Hydro Ottawa's capital plans and the company's financial capability to fund investments.

The final, detailed forecast of capital expenditures resulted in a calculation of rate base for each year of 2016 through 2020. With the calculation of rate base for each year, Hydro Ottawa proposes to determine, for rate making purposes, the return on investment on the annual rate base and adjust rates each year to recover this return on investment. This step of the approach addresses a number of the guiding principles above.

1) The final detailed forecast of capital expenditures ensures that a safe and reliable electrical service is provided to the customers of Hydro Ottawa.
2) The final detailed forecast and subsequent budget provides incentives to prioritize pace and effectively manage the annual budgets.
3) The recovery of return on investment for large capital expenditures, on an annual basis, provides customers with timely and appropriate rates for the cost of providing service. This eliminates potential intergenerational rate

increases that arise when the return on large capital expenditures is not incorporated into rates until a subsequent re-basing application.

4) The recovery of return on investment for large capital expenditures, on an annual basis, ensures that those customers who benefit from the service associated with the expenditures are, in fact, the customers paying for the service.

5) The timely recovery of return on investment of the large capital expenditure from 2016 – 2020 ensures Hydro Ottawa is financially capable of continuing to fund large capital expenditures into the future, so safe and reliable electrical service may continue to be provided to the customers of Hydro Ottawa.

Hydro Ottawa's capital expenditure plan for the 2016-2020 period proposes an average gross annual expenditure of $130 million per year. Hydro Ottawa fully expects this level of annual capital expenditure will be sustained, if not increased through the decade from 2020-2030.

The proposed annual expenditure level is significantly greater than annual expenditure levels set out in previous Hydro Ottawa rate applications but is consistent with the 2013-2015 capital spend levels for distribution plant. What's more the annual expenditure levels are necessary to effectively address all the key areas outlined above in order to continue to provide customers with safe, reliable service at a reasonable rate. By comparison, between 2006 and 2009, Hydro Ottawa's average annual net expenditure level was approximately ~~$60~~ 67 million per year (gross expenditure average was ~~$75~~ 89 million per year).

To support this level of annual capital expenditure over the five year period, Hydro Ottawa requires a financial sustainability model which provides timely return on invested capital. The financial model under the OEB's 4th generation IRM model does not provide appropriate timing of return on capital expenditures for Hydro Ottawa due to the significant percentage differential between net capital expenditures per year and annual

depreciation expense. ~~In Hydro Ottawa's case, the differential for the years 2016 to 2020 is approximately 245% or approximately $60 million per year.~~ Table 2 below compares Hydro Ottawa's forecasted annual capital expenditure requirements to its annual forecasted depreciation expense to illustrate that Hydro Ottawa's capital requirements are over two times and as much as three and a half times the level of forecasted depreciation. Hydro Ottawa's annual increases in capital expenditures and depreciation outpaces inflationary increases to revenue available under the IRM regime rendering the latter an inappropriate mechanism for recovering Hydro Ottawa's capital needs.

Table 2 – Capital Expenditure vs. Depreciation

($000s)	**2016**	**2017**	**2018**	**2019**	**2020**
Capital Expenditures	$145,430	$149,073	$119,418	$120,982	$119,538
Depreciation	$40,826	$44,145	$47,047	$48,949	$50,295
Multiple	3.5	3.3	2.5	2.4	2.3

4.3.2 OM&A Budget Forecasts

To support Hydro Ottawa's operation, maintenance and administrative proposed expenditures ("OM&A), Hydro Ottawa has put forth a detailed budget and analysis of its OM&A costs for 2016. For the 2016 test year, a budget process was completed in 2014 to identify the OM&A needs of Hydro Ottawa. The budget memo directed division leaders to develop the 2016 OM&A budget under certain parameters for ongoing programs and projects and sought identification by individual divisions of extraordinary or unique programs and projects.

For 2017 through 2020 OM&A costs are calculated based upon a formulaic adjustment mechanism. This formulaic adjustment would result in the costs for OM&A included for rate making purposes being delinked from the actual costs incurred by the Company for OM&A expenses for the same period. Following the establishment of a baseline budget for 2016, Hydro Ottawa has chosen to adjust the 2016 test year OM&A by "I" – "X"

formula for the each year of 2017 through 2020 where "I" refers to inflation and "X" refers to productivity. This formulaic adjustment is consistent with the OEB's policy framework under the RRFE where rates charged to customers are de-linked from the costs of operating the utility.

This approach creates an incentive for the Company to seek out productivity initiatives during this period in order to meet ever growing OM&A costs and pass those benefits of the productivity initiatives on the customer during the Custom IR period and in the subsequent 2021 – 2025 rate timeframe. See below for a discussion of how Hydro Ottawa proposes to define the I-X.

4.3.3 Proposed Rate Adjustments

Hydro Ottawa proposes to establish final rates for 2016, 2017 and 2018, as part of this application and to establish final rates for 2019 and 2020 based on capital requirements plus updated inflation and cost of capital parameters. The proposal is to establish the forecast capital expenditures and resulting rate base for 2016, 2017 and 2018. In addition OM&A costs would be established for 2016 and adjusted by formula for 2017 and 2018, based upon a forecast for inflation and a fixed productivity adjustment. The cost of capital parameters will be updated based upon the OEB's prescribed 2016 rates for deemed short term debt and return on equity ("ROE") with long term debt being a weighted average of embedded and forecast deemed rates calculated as discussed in E-1-1. The cost of capital parameters would not be updated annually for 2017 and 2018.

Hydro Ottawa also proposes to establish final rates for 2019 and 2020 in the fall of 2018, based upon the following parameters:

a) Capital expenditures and rate base – 2019 and 2020 capital expenditures and corresponding rate base will be calculated based upon the capital expenditure forecast and rate base forecast contained in this application.
b) OM&A – OM&A expense will be calculated based upon the updated inflation forecast of the Conference Board of Canada ("CBofC"), released in fall 2018 for 2019 and 2020.

c) Cost of Capital parameters – any adjustment to the cost of capital parameters will be based upon the OEB's prescribed rates for 2019 (short term debt, and ROE) released in the fall of 2018. The OEB prescribed rates for 2019 will also apply to 2020 rates for Hydro Ottawa. Long term debt will be a weighted average of embedded and forecast deemed rate at that time as outlined in E-1-1.

Hydro Ottawa's proposal to fix final rates for three years (2016-2018) then adjust the rates only to update for inflation and cost of capital variables. This is intended to build in rate protection for Hydro Ottawa's customers and to provide operating and business certainty to Hydro Ottawa and its shareholder. Hydro Ottawa recognizes that this is a departure from other Custom IR proposals such as those filed by Horizon and Oshawa that have a built in mechanism through which rates can be adjusted annually but the Company stands by the merits of proposing fixed and final rates for the first three years of its five year Custom IR plan.

4.4 Custom IR Rate-Setting Framework

Consistent with Hydro Ottawa's letter to the Board dated December 22, 2014, Hydro Ottawa has opted to apply for rates based on a Custom IR framework. Hydro Ottawa propose a custom IR framework on the grounds that it must undertake unprecedented infrastructure investments in the near to medium term to avoid risks to system and service reliability.

The Custom IR option is the best option for Hydro Ottawa and its customers to ensure the Company has the financial capacity to increase its investments to replace system assets that have reached the end of their useful life. The other rate making approaches identified by the OEB in the RRFE are deficient insofar as they would not result in sufficient capital funding to support Hydro Ottawa's increasing investment requirements.

4.4.1 Capital Expenditures

For all these reasons, Hydro Ottawa's application proposes to have its capital investment requirements fully funded on a five year forecasted cost of service basis. Refer to Exhibit B-1-2(A)-(C) for details on Hydro Ottawa's capital requirements.

4.4.2 Operations, Maintenance & Administrative (OM&A)

For OM&A, Hydro Ottawa proposes a budget for 2016 and thereafter to adjust the 2016 test year OM&A by "I" – "X" (inflation minus productivity) formula for the each year of 2017 through 2020. This formulaic adjustment is consistent with the OEB's policy framework under the RRFE where rates charged to customers are de-linked from the costs of operating the utility.

For the inflation factor, Hydro Ottawa proposes to use the GDP-IPI forecast from the Conference Board of Canada ("CBofC") for the period of 2017 and 2018. The CBofC only provides a three-year forward forecast for GDP-IPPI or CPI. The CBofC has forecast GDP-IPPI at 2.1% for each of 2017 and 2018. For application purposes, Hydro Ottawa has used the CBofC's 2018 forecast of GDP-IPPI as a placeholder for both 2019 and 2020. Hydro Ottawa will update the forecast for GDP-IPPI for 2017 and 2018 using the CBofC's 2015 fall forecast.

Hydro Ottawa will use the 2017 fall forecast of the CBofC to establish the final inflation adjustment for OM&A for 2019 and 2020.

To derive the productivity factor Hydro Ottawa has relied upon the empirical evidence submitted by expert witnesses in the OEB's Report of the Board entitled *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379). In that proceeding, four experts put forth reports on an appropriate X factor to be used by electricity distributors in Ontario. Table 3 provides a summary of final results of each expert.

Table 3 – Summary of X Factor Results

Expert	X Factor
L. Kaufmann, Pacific Economics Group Research, LLC	-0.33 %
S. Fenrick, Power Systems Engineering	-1-10 %
A. Yatchew, University of Toronto	- 0.75 %
F. Cronin,	-2.40 %
Average	-1.145

Hydro Ottawa contends that this is the only empirical evidence of Ontario electricity distributors' productivity trends over the last 10 years that is available to Hydro Ottawa. Hydro Ottawa has chosen to use the average productivity trend number from all of the studies. In this way, Hydro Ottawa has not endorsed any of the recommendations and has given each recommendation equal weight. The productivity adjustment chosen would apply to each year for the period of 2016 to 2020. Please see Exhibit D-1-4 for details on the productivity initiatives of Hydro Ottawa.

Therefore, to determine the annual increase in OM&A for the 2017 through 2020 period, the following Table summarizes Hydro Ottawa's recommendations:

Table 4 – Proposed OM&A Increase for 2017 to 2020

	2017	2018	2019*	2020*
Inflation (GDP-IPPI) (%)	2.1	2.1	2.1	2.1
Productivity (%)	-1.145	-1.145	-1.145	-1.145
Annual OM&A Adjustment (%)	3.245	3.245	3.245	3.245

* Values for 2019 and 2020 are for illustrative purposes

4.4.3 Y Factor

Hydro Ottawa further proposes to introduce a Y factor to recover the costs associated with the construction of its new facilities. The Y factor recovers routine or expected cost changes outside the scope of the annual adjustment mechanism; these are considered to be a cost pass-through. Hydro Ottawa proposes to use a Y factor to pass along to ratepayers the costs associated with the construction of the administrative and operational buildings as outlined in section 3.4.5.3 of the DSP. For further details on Hydro Ottawa's Y Factor proposal refer to Exhibit I, Tab 1, Schedule 2.

4.4.4 Z Factor

Pursuant to the OEB's policies related to the treatment of unforeseen events as set out in *The Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*[3] as may be revised, Hydro Ottawa reserves the right to file a Z factor application to recover costs resulting from events or initiatives having a material impact to Hydro Ottawa's cost or revenue structure.

4.4.5 Earning Sharing Mechanism

Hydro Ottawa proposes to include an earning sharing mechanism as a key feature of its Custom IR Application. Earnings sharing mechanisms are features of incentive regulation frameworks that permit the sharing of utility earnings between its shareholder and/or its customers when earnings rise above or fall below a certain threshold. Earnings sharing is a mechanism through which earnings may be passed along to the customer in the form of rate reductions or rate offsets. Hydro Ottawa is proposing an asymmetrical earning sharing mechanism such that it is only proposing to share earnings that are above a basis point threshold above Hydro Ottawa's return on equity but the company will not impose a corresponding rate adjustment if its earnings fall below a basis point threshold of its return on equity.

Hydro Ottawa proposes the following formula for its earnings sharing mechanism.

Table 5 – Hydro Ottawa's Earnings Sharing Proposal

#	Threshold	Treatment
1	Under Earning	borne entirely by shareholder
2	0 – 150 basis points	fully retained by shareholder
3	151- 250 basis points	50:50 sharing of ratepayer/shareholder
4	251 and above	90:10 sharing of ratepayer/shareholder

[3] Available at http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Report_of_the_Board_3rd_Generation_20080715.pdf

4.4.6 Monitoring and Outcome Measurement

Hydro Ottawa proposes to provide the following information as part of the annual written reporting process to be filed with the OEB:

a) Hydro Ottawa's OEB Scorecard results
b) Annual update on actual capital expenditures by program type, versus, budgeted capital expenditures by program type and appropriate variance analysis;

For further details on Hydro Ottawa's proposed written annual reporting proposals refer to Exhibit A-2-2.

4.4.7 Off Ramps

Hydro Ottawa proposes to apply the OEB's existing policy with respect to off-ramps. The RRFE Report sets out the off ramp trigger which is equal to the annual return on equity review where the dead band equals plus or minus 300 basis points. In the event the 300 basis point dead band is triggered a regulatory review may be initiated.

5.0 SUMMARY OF APPLICATION KEY COMPONENTS

5.1 Capital Expenditures

Hydro Ottawa developed the forecasted capital expenditures for the years 2016 – 2020, based upon a process of identification and analysis of distribution system needs, customer expectations and requirements for general plant capital.

The total capital expenditure forecast underwent a number of iterations to address issues of pace, priority, rate impact, resource capacity and financing capability. For example, a new capital expenditure area relating to Hydro One transmission costs was accommodated to a certain level by reducing other areas of capital expenditure. As well, pacing and prioritization of other capital projects (typically IT expenditures) were adjusted through a number of iterations so that the resource capacity of company could complete the projects in a timely manner and to pace the total expenditures of other capital projects more evenly throughout the 2016 – 2020 timeframe. Please see Exhibits B1-1 and B-1-2 for details.

A detailed capital expenditure for each year from 2016 – 2020 provides the basis of the calculation for rate base. The capital expenditure is detailed by asset type and the corresponding amortization is calculated. Hydro Ottawa has used the half year rule in the calculation of rate base for each year of 2016 -2020. Please see Exhibit B-1-1 for details.

Hydro Ottawa's capital expenditure plan for the 2016-2020 period proposes an average gross annual expenditure of $130 million per year. Forecasted gross capital expenditures for the 2016 test year are approximately $145.4 million which represents an increase of approximately $109 million or 26 % from Hydro Ottawa's last rebasing application in 2012. For the 2016-2020 period, Hydro Ottawa's proposed capital expenditures are as follows:

Table 6 – Summary of Capital Expenditures for Test Years

($000s)	2016	2017	2018	2019	2020
Capital Expenditures	145,430	149,073	119,418	120,982	119,538

Source: table 1.1.1 DSP Exhibit B-1

For greater detail on Hydro Ottawa's 2016-2020 capital funding requirements please refer to Hydro Ottawa's Distribution System plan and associated schedules and appendices in Exhibit B-1-2. The DSP outlines Hydro Ottawa's Asset Management Process and Capital Expenditure Plan, in line with the OEB's Chapter 5 Consolidated Distribution System Plan Filing Requirements, providing evidence for good distributor planning.

5.2 Rate Base

Hydro Ottawa's requested rate base for the 2016 test year is $923,306,000 which represents an increase of approximately $254,244,000 or 28% from the total rate base amount approved by the OEB in Hydro Ottawa's last rebasing application in 2012 (EB2011-0054). Table 7 sets out the rate base requested for each of the test years 2016-2020.

Table 7 – Summary of Rate Base for Test Years

($000s)	2016	2017	2018	2019	2020
Rate Base	923,306	970,582	1,020,297	1,050,724	1,094,270

With respect to costs for renewable energy connections, Hydro Ottawa has provided a historical and forwarding looking forecast of system access costs arising from embedded generations as captured in section 3.4 of the Distribution System Plan available in Exhibit B-1-2.

5.3 Operations, Maintenance and Administrative (OM&A)

Hydro Ottawa's OM&A costs are significantly influenced by its requirement to operate and maintain a safe and reliable distribution grid, provide service levels that are satisfactory to customers while ensuring its continued compliance with all legislative and

regulatory obligations. Among other things, this requires that Hydro Ottawa strategically manage its workforce in a manner that allows it to replace retiring workers with new tradespeople and respond to the changing dynamics of the market and operating environment within which it is tasked with distributing electricity to customers.

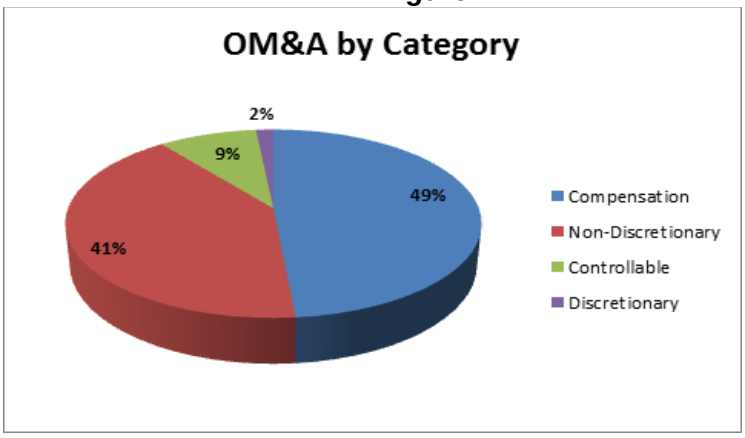
The proposed OM&A costs for the test years range from $87.1 million in the 2016 test year to $99.0 million in the 2020 test year.

Table 8 – Hydro Ottawa's Proposed OM&A Expenditures

($000s)	**2016**	**2017**	**2018**	**2019**	**2020**
OM&A Expenditures	$87,106	$89,932	$92,850	$95,863	$98,974

Hydro Ottawa's OM&A costs arise from four distinct sources, namely compensation, non-discretionary, controllable and discretionary costs. Figure 2 below denotes that compensation costs represent 49% of Hydro Ottawa's OM&A costs while 41% are non-discretionary costs, 9% are controllable and only 2% are discretionary.

Figure 2



Source: Hydro Ottawa 2014 OM&A

For a discussion of the costs captured in each of the categories contained in Figure 2 and for a description of Hydro Ottawa's proposed OM&A costs for each of the 2016-2020 test years and for a discussion of the year over year variances by major category, please refer to Exhibit D-1-2.

Table 9 below provides a summary of the overall OM&A cost drivers and cost trends.

Table 9 – OM&A by Cost Driver

OM&A ($M)	Last Rebasing Year (2012 Actuals)	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	~~2015 Bridge Year~~	2015 Bridge Year	2016 Test Year
Reporting Basis							
Opening Balance	73.1	73.1	~~75.8~~	75.8	~~80.8~~	80.9	83.7
Workforce Planning		-	~~0.2~~		~~0.3~~	0.6	0.4
Collective Agreement/Annual progressions		1.1	~~1.2~~	1.7	~~1.3~~	2.3	1.4
Vacancy and Vacancy Allowance		-	~~(1.6)~~		~~(0.5)~~	(2.1)	(0.1)
Benefits & Pensions		0.1	~~1.7~~	0.6	~~(0.3)~~	0.8	1.0
Vegetation Management		0.4	~~0.3~~	1.5	~~0.9~~	(0.3)	(0.4)
Underground Locates		0.2	~~0.1~~	0.1	~~0.3~~	0.3	0.3
Changes in Capital and Allocations		(0.6)	~~0.2~~	0.4	~~0.1~~	(0.4)	(0.2)
Postage		(0.1)	~~0.7~~	0.8	~~0.2~~	0.1	-
IT Maintenance		0.5	~~1.2~~	1.2	~~0.4~~	0.4	0.5
Bad Debts		0.8	~~(0.4)~~	(0.4)	~~(0.3)~~	(0.3)	0.4
Inventory Scrap recovery reclass out of OMA		-	~~0.8~~	0.6	~~$ -~~		$ -
Inflation		-			~~0.8~~	0.8	0.8
Other Costs/(Cost reductions)	$ -	0.3	~~0.6~~	(1.4)	~~(0.3)~~	0.6	(0.7)
Closing Balance	73.1	75.8	~~80.8~~	80.9	~~83.7~~	83.7	87.1

For a full discussion of Hydro Ottawa's OM&A programs, the costs drivers and year over year variances to the company's OM&A costs, please refer to Exhibit D-1-3.

5.3.1 Inflation Rates and Financial Assumptions

Hydro Ottawa has assumed an inflation rate of 2.13% for 2015 and 2.01% for 2016 for all non-compensation related costs. For the 2017-2020 rate period, an inflation factor of 2.1% is applied to OM&A expenditures consistent with the Conference Board of Canada's GDP IPI.

5.3.2 Compensation Costs

Hydro Ottawa's forecasted total compensation costs for the 2016 test year are $71,944,283. This represents an $11,038,541 increase or an approximate 15% increase over the 2012 Board approved. Labour costs are adjusted to reflect market conditions for non-unionized employees and to align with the collective agreement annual rate adjustment for unionized employees. For more information regarding Hydro Ottawa's compensation strategy please refer to Exhibit D, Tab 1, Schedule 8.

For further details on Hydro Ottawa's OM&A proposals see Exhibits D-1-1, D-1-2 and D-1-3.

5.4 Revenue Requirement

Hydro Ottawa requests approval for service revenue requirement for each of its 2016-2020 Test Years, base revenue requirements for each of its 2016-2020 Test Years and resulting rates and riders based on Hydro Ottawa's forecast capital expenditures, OM&A, depreciation expense, cost of capital, payment in lieu of taxes ("PILS") and revenue from other sources. For the 2016 Test Year, Hydro Ottawa requests a service revenue requirement of $187,269,000 which represents an increase of $18,968,000 or 11% from the service revenue requirement previously approved by the Board in 2012 during Hydro Ottawa's last rebasing.

The main cost drivers underlying Hydro Ottawa's test year revenue requirements are the result of increases to Hydro Ottawa's rate base due to the significant capital investments that Hydro Ottawa must undertake so that it may continue to provide a safe and reliable electricity service to the residents and businesses in the City of Ottawa and Village of Casselman. Other cost drivers impacting Hydro Ottawa's revenue requirement include increases to amortization expense, increase to OM&A expenses, increases in interest and return on equity. For further details regarding Hydro Ottawa's revenue requirement and related cost drivers please refer to Exhibit F-1-1

Table 10 – Hydro Ottawa's Revenue Requirement

	$000	$000	$000	$000	$000
	2016	2017	2018	2019	2020
Return on Rate Base	54,379	58,359	62,148	64,531	67,573
Distribution Expenses (not including amortization)	87,106	89,932	92,850	95,863	98,974
Amortization	40,826	44,145	47,047	48,949	50,295
Payment in Lieu of Taxes	4,958	4,799	6,074	8,473	7,587
Service Revenue Requirement	187,269	197,235	208,120	217,816	224,430
Less Revenue Offsets	11,700	11,565	11,722	11,802	11,898
2012 Base Revenue Requirement	175,570	185,670	196,398	206,014	212,532
Transformer Ownership Allowance	1,125	1,114	1,109	1,106	1,105
Revenue Requirement from Rates	176,694	186,784	197,507	207,120	213,637
Forecasted Load at 2015 Rates	159,358	158,984	159,419	159,975	160,461
Cumulative Revenue Deficiency (over 2015)	**(17,337)**	**(27,800)**	**(38,088)**	**(47,146)**	**(53,176)**
Yearly Revenue Deficiency over 2015	**(17,337)**	**(10,464)**	**(10,288)**	**(9,057)**	**(6,030)**

Amortization expense has been calculated each year based upon the assets in rate base. Each year new assets are incorporated in rate base with their corresponding amortization rate while older assets are retired with their corresponding amortization rate. A new, weighted average amortization rate is calculated for each year. Please see Exhibit D-3-1 for details. Finally, a detailed Payment in Lieu of Taxes ("PILS") calculation has been completed for each year to determine the appropriate cost for PILS to be included in revenue requirement for each year. Please see Exhibit D-4-1 for details.

5.5 Bill Impacts

In developing its initial and test year capital and OM&A budgets Hydro Ottawa was careful to have due regard to the impacts bill increases may have on its customers. Hydro Ottawa's objective was to keep the total bill impacts for each of its customers as minimal as possible.

Hydro Ottawa anticipates that, on average for each of the next five years, the bill impacts resulting from Hydro Ottawa's application as filed (including rate riders associated with Hydro Ottawa's proposed new facilities) will be on average approximately $1.35 per month for residential customers and $4.57 per month for General Service customers.

Table 11 below provides a summary of the total bill impacts for typical customers in all classes. Further details regarding Hydro Ottawa's proposed bill impacts are available in Exhibit H-12-1.

Table 11 – Hydro Ottawa Estimated Bill Impacts

Rate Class		2015 Approved	2016 Proposed	2017 Proposed	2018 Proposed	2019 Proposed	2020 Proposed
Residential (800 kWh)	Distribution Charge	$28.39	$31.05	$32.49	$33.78	$34.68	$35.15
	Change in Distribution Charge		$2.66	$1.44	$1.29	$0.90	$0.47
	% Distribution Increase		9.37%	4.64%	3.97%	2.66%	1.36%
	% Increase of Total Bill		~~1.84%~~ 1.31%	~~1.06%~~ 1.59%	0.93%	0.65%	0.34%
General Service <50kW (2000 kWh)	Distribution Charge	$58.72	$65.95	$70.55	$74.85	$78.95	$81.60
	Change in Distribution Charge		$7.23	$4.60	$4.30	$4.10	$2.65
	% Distribution Increase		12.31%	6.97%	6.09%	5.48%	3.36%
	% Increase of Total Bill		~~2.11%~~ 1.49%	~~1.41%~~ 2.03%	1.30%	1.22%	0.78%
General Service 50-1,499 kWh (250KW)	Distribution Charge	$1,153.10	$1,276.35	$1,329.05	$1,377.48	$1,411.05	$1,423.25
	Change in Distribution Charge		$123.26	$52.70	$48.43	$33.58	$12.20
	% Distribution Increase		10.69%	4.13%	3.64%	2.44%	0.86%
	% Increase of Total Bill		~~0.55%~~ -0.26%	~~0.30%~~ 1.12%	0.28%	0.19%	0.07%
General Service 1,500-4,999 kWh (2500 KW)	Distribution Charge	$12,915.68	$14,300.50	$15,118.75	$15,850.50	$16,401.75	$16,707.75
	Change in Distribution Charge		$1,384.82	$818.25	$731.75	$551.25	$306.00
	% Distribution Increase		10.72%	5.72%	4.84%	3.48%	1.87%
	% Increase of Total Bill		~~0.49%~~ -0.16%	1.12%	0.41%	0.31%	0.17%
Large Use (7500 KW)	Distribution Charge	$40,078.07	$44,383.00	$46,959.50	$49,690.50	$52,139.25	$53,806.00
	Change in Distribution Charge		$4,304.93	$2,576.50	$2,731.00	$2,448.75	$1,666.75
	% Distribution Increase		10.74%	5.81%	5.82%	4.93%	3.20%
	% Increase of Total Bill		-0.23%	1.45%	0.50%	0.44%	0.30%

Sentinel Lighting (0.4KW)	***Distribution Charge***	*$6.63*	*$8.08*	*$8.58*	*$9.02*	*$9.42*	*$9.72*
	Change in Distribution Charge		*$1.44*	*$0.50*	*$0.44*	*$0.40*	*$0.30*
	% Distribution Increase		*21.73%*	*6.24%*	*5.09%*	*4.43%*	*3.21%*
	% Increase of Total Bill		*~~7.34%~~ 6.91%*	*~~2.41%~~ 2.82%*	*2.05%*	*~~1.86%~~ 1.84%*	*~~1.34%~~ 1.36%*
Street Lighting (1 KW)	***Distribution Charge***	*$4.57*	*$4.99*	*$5.24*	*$5.47*	*$5.63*	*$5.88*
	Change in Distribution Charge		*$0.42*	*$0.24*	*$0.23*	*$0.17*	*$0.24*
	% Distribution Increase		*9.29%*	*4.90%*	*4.36%*	*3.02%*	*4.32%*
	% Increase of Total Bill		*~~1.53%~~ 0.00%*	*~~0.92%~~ 2.45%*	*~~0.84%~~ 0.86%*	*0.61%*	*~~0.93%~~ 0.90%*
Unmetered Scattered Load (470 kWh)	***Distribution Charge***	*$14.72*	*$16.12*	*$16.89*	*$17.58*	*$18.26*	*$18.69*
	Change in Distribution Charge		*$1.40*	*$0.77*	*$0.69*	*$0.69*	*$0.42*
	% Distribution Increase		*9.52%*	*4.74%*	*4.06%*	*3.91%*	*2.32%*
	% Increase of Total Bill		*~~1.69%~~ 1.08%*	*~~1.00%~~ 1.61%*	*~~0.87%~~ 0.88%*	*0.87%*	*0.53%*

5.6 Budgeting and Accounting Assumptions

See sections 4.2 above for a description of the financial planning and budgeting process used to derive Hydro Ottawa's capital and operational budgets and all the accounting and inflationary assumptions used.

5.7 Load Forecast Summary

Hydro Ottawa's forecasted energy consumption for the 2016 Test year is 7,440,624 kWh. This is 233,334kWh or 3% lower than the 2012 Board Approved kWh forecast. Hydro Ottawa's forecasted number of customers for the 2016 test year is 325,238 representing an increase of 5.6% over the 2012 Board Approved. Table 12 below provides a high level summary of Hydro Ottawa's forecasted load forecast.

Table 21 – Hydro Ottawa's Estimated Load Forecast

Year	Total Sales (GWh)	Total Customers
2016	7,441	325,238
2017	7,380	329,294
2018	7,366	333,321
2019	7,364	337,306
2020	7,364	341,241

Note: Customer number do not include Streetlighling, Sentinel Lights, Unmetered and Standby

Hydro Ottawa has provided a five year detailed class specific weather normalized load forecast and customer connection forecast for each rate class in Exhibit C-1-1. The load forecast incorporates the commitments of Hydro Ottawa for conservation to the Ontario government.

5.8 Cost of Capital

The components of the cost of capital have been determined for each year. Hydro Ottawa has used the following debt/equity ratio for all years – 4% short term debt, 56% long term debt and 40% equity. As part of this application, Hydro Ottawa has used as a placeholder for determination of the deemed short term debt rate, deemed long term debt rate and the return on equity. The placeholder Hydro Ottawa has used for both of these components is the prescribed rates of the OEB issued on November 20, 2014.

Hydro Ottawa proposes to update short term debt and ROE with the effective OEB-prescribed rates for 2016 which will be announced in fall 2015. The long term debt is a weighted average of embedded and forecast deemed rates calculated as outlined in E-1-1. Hydro Ottawa has incorporated the embedded cost of long term debt in its calculation of cost of capital for that portion of the long term debt that has been issued to third party bondholders.

5.9 Cost Allocation and Rate Design

Hydro Ottawa has prepared a cost allocation model for each of the five Test Years using the Board's cost allocation methodologies and the Board's V3.2 Cost Allocation Model Hydro Ottawa's 2016 base revenue requirement has been allocated to the company's nine rate classes. The resulting revenues-to-cost ratios for each rate class were determined using the total revenues over costs for each test year pursuant to the OEB's guidelines set out in EB-2010-0219.

Hydro Ottawa engaged Elenchus to undertake a Cost Allocation Model study to determine whether refinements were necessary to better reflect the OEB's principle of

cost causality in its cost allocation to customers. The result of the consultant's study indicated that some classes of customers fell outside the acceptable revenue to cost range as established by the Board. Hydro Ottawa adjusted two classes that fell outside the acceptable revenue to cost range, namely Sentinel lights and unmetered scattered load. The study also indicated that the Small Commercial classes fixed charge could be increased.

Consistent with the Board policy entitled "A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410) that seeks to gradually adjust the fixed/variable portions of customer bills, Hydro Ottawa proposes by way of this application increases to the fixed elements of its rates.

5.10 Deferral and Variance Accounts

The Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EB-2008-0046) ("EDDVAR") classifies variance and deferral accounts into two groups, namely Group 1 and Group 2. In this application, Hydro Ottawa proposes to clear both Group 1 and Group 2 deferral accounts. The total net DVA balances proposed for disposition are $8.2 million. The proposed disposition period is one year. Disposition for RPP customers is approximately $7.0 million and $1.2 million for non-RPP customers.

Hydro Ottawa Limited ("Hydro Ottawa") is proposing new rate riders to clear a number of Deferral and Variance ("DVAs") balances, including the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA").

The total net DVA balances proposed for disposition are $8.2 million. The proposed disposition period is one year.

1) Y Factor Deferral and Variance account to record costs to be recovered from the construction of Hydro Ottawa's new head office and operations buildings;
2) Proceeds of Sale of Existing Facilities to capture the after tax gain/loss from the sale of Hydro Ottawa current facilities;

3) Energy East – Trans Canada Pipeline – Hydro Ottawa requests a sub-account be added to US ofA 1508 Other Regulatory Assets deferral account to capture costs associated with consultations regarding the TransCanada Pipeline Limited's Proposed Energy East Pipeline Project;
4) Monthly Billing – Hydro Ottawa requests a deferral account to record costs associated with the transition to monthly billing per EB-2014-0198;
5) Loss on Disposal of Fixed Assets
6) Earnings Sharing Mechanisms to record earnings to be shared above prescribed threshold.

For further information regarding the DVA accounts, the amounts proposed for clearance, proposals for new deferral and variance accounts and other DVA information please refer to Exhibit I, specifically I-1-1, I-1-2 and I-8-1.

6.0 CONCLUSION

Over the next five years, the electricity industry in Ontario will undergo transformative change not only to how the market is structured but predictably to how the market is regulated. The government will continue to implement changes foreseen and unforeseen in the Long Term Energy Plan and new technology and new players in the market risk disrupting the fundamental business models upon which the industry is constructed potentially triggering a review of how distributors are regulated. During the five years of Hydro Ottawa's Custom IR application, it fully expects to see increases to growth of distributed generation and further electrification of transportation such as via the City of Ottawa's light rail initiatives and electric vehicles. Hydro Ottawa further anticipates increased customer and third party demand for system monitoring technologies and more "cloud" based solutions. Against this backdrop is an economy that still recovering from a prolonged economic downturn and governments that are introducing new forward energy related or impacting policies.

It is for these reasons that Hydro Ottawa has structured its Custom IR in a manner that ensures it has the funding necessary to build and harden a safe reliable electricity distribution system and has enough operational funding to manage the known and anticipated requirements leaving the balance to be met through productivity and innovative initiatives and solutions. Table 13 below denotes all the components of its rate application and the treatment of each component for each year before Hydro Ottawa returns in 2017 to have certain components of its rate framework adjusted for 2019 and 2020.

Table 13 – Revenue Requirement Components for 2016 to 2018

	2016	2017	2018
Load forecast	Annual forecast	Annual forecast	Annual forecast
Capital expenditure	Annual forecast	Annual forecast	Annual forecast
Rate base	Annual forecast	Annual forecast	Annual forecast
Amortization	Annual forecast	Annual forecast	Annual forecast
PILS	Annual forecast	Annual forecast	Annual forecast
Inflation factor	CBoC forecast	CBoC forecast	CBoC forecast
Productivity factor	Fixed	Fixed	Fixed
OM&A	Annual forecast	Formulaic	Formulaic
Short Term Debt	Fixed	Fixed	Fixed
Long Term Debt (embedded)	Actual	Actual	Actual
Long Term Debt (deemed)	Annual Forecast	Annual Forecast	Annual Forecast
Return on Equity	Fixed	Fixed	Fixed

By way of this, its Custom IR application, Hydro Ottawa both undertakes certain manageable risks and is incentivized to seek out additional rewards. For these reasons, Hydro Ottawa respectfully requests that the OEB approve this Custom IR application.

AUDITED FINANCIAL STATEMENTS FOR 2012, 2013 and 2014

Hydro Ottawa Limited's Audited Financial Statements for 2013 (with 2012 comparatives) are attached as Attachment A-4(A). The 2014 Audited Financial Statements ~~will be filed~~ are attached as Attachment A-4(B) ~~when available.~~

Hydro Ottawa Limited

Financial Statements

December 31, 2014

Table of Contents

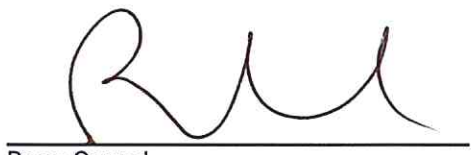
Report of Management

Management is responsible for the integrity of the financial data reported by Hydro Ottawa Limited ['the Company']. Fulfilling this responsibility requires the preparation and presentation of financial statements using management's best judgment and estimates in accordance with Canadian generally accepted accounting principles, applied on a basis consistent with the preceding year.

Management maintains appropriate systems of internal control and corporate-wide policies and procedures, which provide reasonable assurance that the Company's assets are safeguarded and that financial records are relevant and reliable.

The Board of Directors of the Company, with the advice of the Audit Committee of Hydro Ottawa Holding Inc., ensures that management fulfills its responsibility for financial reporting and internal control. At regular meetings, the Audit Committee, including the Chair of the Board of Directors of the Company, reviews internal controls and financial reporting matters with management for Hydro Ottawa Holding Inc. and its subsidiaries. The Chair of the Board of Directors of the Company, as well as the Chief Executive Officer and the Chief Financial Officer, advise the Board of Directors of the Company of any matters of concern raised by the Audit Committee in reviewing the financial affairs of the Company.

On behalf of Management,



Bryce Conrad
President and Chief Executive Officer

Geoff Simpson
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Hydro Ottawa Limited

We have audited the accompanying financial statements of **Hydro Ottawa Limited**, which comprise the balance sheet as at December 31, 2014, and the statement of income, comprehensive income and retained earnings, and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of **Hydro Ottawa Limited** as at December 31, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ottawa, Canada,
April 23, 2015

Chartered Professional Accountants
Licensed Public Accountants

Hydro Ottawa Limited

Statement of Income, Comprehensive Income and Retained Earnings
Year ended December 31
[in thousands of Canadian dollars]

		2014		2013
Revenue [Note 22]				
Power recovery	**$**	**799,272**	$	768,079
Distribution sales		**156,616**		152,392
Other revenue		**32,554**		32,406
		988,442		952,877
Expenses				
Purchased power [Note 22]		**799,272**		768,079
Operating costs [Note 22]		**106,474**		99,751
Depreciation		**30,249**		29,388
Amortization		**5,791**		7,711
		941,786		904,929
Income before financing costs and payments in lieu of corporate income taxes		**46,656**		47,948
Financing costs		**17,873**		15,759
Income before payments in lieu of corporate income taxes		**28,783**		32,189
Payments in lieu of corporate income taxes [Note 19]		**912**		6,750
Net income and comprehensive income		**27,871**		25,439
Retained earnings, beginning of year		**102,513**		92,074
Dividends declared and paid [Note 16]		**(15,000)**		(15,000)
Retained earnings, end of year	**$**	**115,384**	$	102,513

Hydro Ottawa Limited

Balance Sheet
As at December 31
[in thousands of Canadian dollars]

	2014	2013
Assets		
Current assets		
Cash	$ 19,421	$ 5,038
Accounts receivable [Notes 4 and 22]	65,290	66,391
Payments in lieu of corporate income taxes receivable	3,728	457
Unbilled revenue [Note 5]	81,806	106,551
Prepaid expenses	940	2,931
Regulatory assets [Note 6]	31	31
Future income tax assets [Note 19]	1,015	818
	172,231	182,217
Non-current assets		
Regulatory assets [Note 6]	20,592	12,441
Property, plant and equipment [Note 7]	697,156	651,577
Intangible assets [Note 8]	67,277	44,733
Future income tax assets [Note 19]	11,055	19,893
Total assets	968,311	910,861
Liabilities and shareholder's equity		
Current liabilities		
Accounts payable and accrued liabilities [Notes 9 and 22]	211,949	179,365
Regulatory liabilities [Note 6]	-	19,173
Regulatory liability for future income tax assets [Note 19]	1,015	818
	212,964	199,356
Non-current liabilities		
Regulatory liabilities [Note 6]	22,141	12,915
Regulatory liability for future income tax assets [Note 19]	11,055	19,893
Employee future benefits [Note 12]	9,836	8,533
Customer deposits	12,459	13,085
Notes payable [Note 13]	417,185	387,185
Asset retirement obligations [Note 11]	206	300
	685,846	641,267
Shareholder's equity		
Share capital [Note 16]	167,081	167,081
Retained earnings	115,384	102,513
	282,465	269,594
Total liabilities and shareholder's equity	$ 968,311	$ 910,861

Contingent liabilities and commitments [Notes 20 and 21]

ON BEHALF OF THE BOARD:

Director

Director

The accompanying notes are an integral part of these financial statements

Hydro Ottawa Limited

Statement of Cash Flows
Year ended December 31
[in thousands of Canadian dollars]

		2014		2013
Net inflow (outflow) of cash related to the following activities:				
Operating				
Net income and comprehensive income	**$**	**27,871**	$	25,439
Items not affecting cash				
Depreciation		**30,249**		29,388
Amortization		**5,791**		7,711
Loss on disposal of capital assets [Notes 7 and 8]		**2,064**		989
Allowance for funds used during construction [Notes 7 and 8]		**(1,857)**		(2,376)
Employee future benefits [Note 12]		**27**		109
Changes in non-cash working capital and other operating balances				
Decrease in accounts receivable		**1,101**		4,381
Decrease (increase) in unbilled revenue		**24,745**		(16,616)
(Increase) decrease in payments in lieu of corporate income taxes receivable		**(3,271)**		754
Decrease (increase) in prepaid expenses		**1,991**		(456)
Increase in regulatory assets, net of liabilities [Note 12]		**(16,807)**		(14,949)
Increase in accounts payable and accrued liabilities [Notes 7 and 8]		**22,376**		4,529
		94,280		38,903
Investing				
Acquisition of property, plant and equipment [Note 7]		**(102,831)**		(107,054)
Acquisition of intangible assets [Note 8]		**(11,485)**		(23,069)
Proceeds from disposal of property, plant and equipment		**834**		1,765
Contributions in aid of construction [Note 7]		**23,625**		21,419
		(89,857)		(106,939)
Financing				
Issuance of notes payable [Notes 13 and 22]		**30,000**		60,000
(Repayment of) proceeds from advances from parent [Notes 14 and 22]		**(4,000)**		26,000
(Decrease) increase in customer deposits [Note 9]		**(1,040)**		435
Dividends paid [Note 16]		**(15,000)**		(15,000)
		9,960		71,435
Net change in cash		**14,383**		3,399
Cash, beginning of year		**5,038**		1,639
Cash, end of year	**$**	**19,421**	$	5,038
Supplementary cash flow information				
Interest paid		**19,579**		18,030
Payments in lieu of corporate income taxes paid		**4,000**		5,783

1. DESCRIPTION OF BUSINESS

Hydro Ottawa Limited [the 'Company'] was incorporated on October 3, 2000 pursuant to the *Business Corporations Act (Ontario)* as mandated by the Ontario government's *Electricity Act, 1998*. The Company is a wholly owned subsidiary of Hydro Ottawa Holding Inc., which in turn is wholly owned by the City of Ottawa.

The Company is a regulated electricity distribution company that owns and operates electricity infrastructure in the City of Ottawa and the Village of Casselman and is responsible for the safe, reliable delivery of electricity to homes and businesses in its licensed service area. In addition to billing for distribution services, the Company invoices customers for amounts it is required to pay to other organizations in Ontario's electricity system for providing wholesale generation and transmission services and for debt retirement.

2. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Part V of the *Chartered Professional Accountants of Canada Handbook* for publicly accountable entities ['pre-changeover Canadian GAAP'], including principles prescribed by the Ontario Energy Board ['OEB'] in the Accounting Procedures Handbook ['AP Handbook']. In the opinion of management, all adjustments necessary for fair presentation are reflected in the financial statements. The financial statements reflect the significant accounting policies summarized below.

(a) Regulation

The Company is regulated by the OEB under the authority of the *Ontario Energy Board Act, 1998*. The OEB is charged with the responsibilities of approving or setting rates for the transmission and distribution of electricity, and ensuring that distribution companies fulfil obligations to connect and service customers.

The Company operates under an incentive regulation mechanism ['IRM'] prescribed by the OEB. Under IRM a distributor first sets base rates through a cost-of-service application every four years. This application determines the appropriate revenue requirement to recover approved costs, and provide a rate of return on a deemed capital structure applied to approved rate base assets. For subsequent years in which no cost-of-service application is filed, rates are adjusted by an inflation factor less a productivity factor.

The Company applies for distribution rates based on estimated costs of service. Once the rate is approved, it is not adjusted as a result of actual costs of service being different from those which were estimated, other than for certain prescribed costs that are eligible for deferral treatment and are either collected or refunded in future rates. The OEB has the general power to include or exclude costs and revenue in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company.

The Company continues to assess the likelihood of recovery of all regulatory assets subject to recovery through a future rate filing. The absence of OEB approval is a consideration in this evaluation. If the requirement for a provision becomes more likely than not, the Company will recognize the provision in operating costs for the period.

The following regulatory treatments have resulted in accounting treatments that differ from pre-changeover Canadian GAAP for enterprises operating in a non-regulated environment:

(i) Regulatory assets and liabilities

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in future rates. Similarly, regulatory liabilities can arise from differences in amounts billed to customers for electricity services and the costs that the Company incurs to purchase these services.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(a) Regulation [continued]

(i) Regulatory assets and liabilities [continued]

The Company accrues interest on the regulatory asset and liability balances as directed by the OEB.

Regulatory assets and liabilities are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months after the reporting period. All other regulatory asset and liability balances are classified as long-term on the balance sheet.

Regulatory balances are comprised principally of the following:

- Regulatory asset/liability refund account ['RARA'/'RLRA'] consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through temporary additional rates referred to as rate riders.

- Settlement variances relate primarily to the charges the Company incurred for transmission services, the commodity, wholesale market operations and the global adjustment that were not settled with customers during the period. The nature of the settlement variances is such that the balance can fluctuate between assets and liabilities over time and they are reported at year end dates in accordance with rules prescribed by the OEB.

- Deferred smart meter costs represent the differences between the amounts funded through rates for smart meters and actual program costs. Program costs include operating, maintenance, depreciation and administrative expenses directly related to smart meters, and a return on smart meter assets.

- Stranded meter costs represent the net book value of conventional meters removed upon the installation of smart meters.

- Other Post-Employment Benefits deferral account ['OPEB deferral account'] was authorized by the OEB in 2011 to record the adjustment to post-retirement benefits relating to the cumulative actuarial gains or losses. This account is adjusted annually to record any changes in the cumulative actuarial gains or losses. No interest charges are recorded on this account as instructed by the OEB.

Other regulatory variances and deferred costs:

- The OEB allows electricity distributors to record in a deferral account the difference between low voltage charges paid to Hydro One Networks Inc. ['HONI'] and those charged to customers.

- The OEB allows electricity distributors to record, in a deferral account, the net cost of providing retailer billing services and transaction request services.

- The OEB approved a deferral account for distributors to record one-time administrative incremental International Financial Reporting Standards ['IFRS'] transition costs, which were not already approved and included for recovery in distribution rates.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(a) Regulation [continued]

(i) Regulatory assets and liabilities [continued]

- In its Guidelines released June 16, 2009, the OEB created four new deferral accounts to allow distributors to begin recording expenditures for certain activities relating to the connection of renewable generation and the development of a smart grid. These deferral accounts were authorized to be used to record qualifying incremental capital investments or operating, maintenance and administrative expenses.

- In its Guidelines released January 5, 2012, the OEB required the Company to record the difference between the actual authorized Conservation and Demand Management ['CDM'] activities and activities included in the Company's load forecast. This variance is recorded in the Lost Revenue Adjustment Mechanism variance account.

- The OEB directed distributors to record the input tax credit savings arising from the elimination of the provincial sales tax and the implementation of the harmonized sales tax on July 1, 2010 in a separate account. The OEB concluded that fifty percent of the balances should be returned to the ratepayers for the period up to the rebasing date, which for the Company was January 1, 2012.

(ii) Contributions in aid of construction

Contributions in aid of construction received from outside sources are used to finance additions to property, plant and equipment. According to the AP Handbook prescribed by the OEB, contributions in aid of construction are treated as a reduction to property, plant and equipment and are depreciated at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

(iii) Allowance for funds used during construction ['AFUDC']

An allowance for the cost of funds used during the construction period has been applied to major capital and development projects.

(iv) Payments in lieu of corporate income taxes ['PILs']

The Company is considered to be a Municipal Electric Utility ['MEU'] for purposes of the PILs regime contained in the *Electricity Act, 1998*, as all of its share capital is indirectly owned by the City of Ottawa and not more than 10% of its income is derived from activities carried on outside the municipal boundaries of the City of Ottawa. The *Electricity Act, 1998* provides that an MEU that is exempt from tax under the *Income Tax Act (Canada)* ['ITA'] and the *Taxation Act, Ontario* ['TAO'] is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount approximating the tax that it would be liable to pay under the ITA and the TAO if it were not exempt from tax.

The Company follows the liability method for recording income taxes in accordance with pre-changeover Canadian GAAP recommendations. Under the liability method, current income taxes payable are recorded based on taxable income. Future income taxes arising from temporary differences in the accounting and tax basis of assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

The AP Handbook provides for the recovery of PILs by the Company through annual distribution rate adjustments as approved by the OEB. The Company recognizes regulatory liabilities and assets for the

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(a) Regulation [continued]

(iv) Payments in lieu of corporate income taxes ['PILs'] [continued]

amounts of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates.

(b) Revenue recognition

The Company recognizes revenue when persuasive evidence of an arrangement exists, services have been delivered, the price has been fixed or is determinable and collection is reasonably assured.

(i) Distribution sales

The Company charges customers for the delivery of electricity, based on rates established by the OEB. The rates are intended to allow the Company to recover its prudently incurred costs and earn a fair return on invested capital. Distribution sales are recognized when electricity is delivered to the customer, as measured by meter readings or usage estimates.

(ii) Power recovery

Power recovery revenue represents the pass-through of the cost of power to the consumer as purchased by the Company and is recognized when electricity is delivered to the customer, as measured by meter readings or usage estimates. Power recovery revenue is regulated by the OEB and includes charges to customers for the electricity commodity, the transmission of electricity and the administration of the wholesale electricity system.

(iii) Unbilled revenue

Unbilled revenue represents an estimate of the electricity consumed by the customers that has not yet been billed as at year end.

(iv) Other revenue

Other revenue related to sales of other services is recognized as services are rendered.

'CDM revenue stems from the delivery of provincial government programs that promote conservation and is recognized on a cost-recovery basis.

(c) Financial instruments

All financial instruments are initially recorded at fair value, unless fair value cannot be reliably determined. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's length transaction between willing parties. The subsequent measurement of each financial instrument depends on the classification elected by the Company.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(c) Financial instruments [continued]

The Company classifies and measures its financial instruments as follows:

- Cash is classified as held-for-trading and is measured at fair value.

- Accounts receivable and unbilled revenue are classified as loans and receivables and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value with the exception of related party transactions which, are measured at the carrying amount determined in accordance with pre-changeover Canadian GAAP Section 3840, Related Party Transactions. Subsequent measurements are recorded at amortized cost using the effective interest rate method, if applicable.

- Accounts payable and accrued liabilities, customer deposits, notes payable and capital contribution obligations are classified as other financial liabilities and are initially measured at their fair value with the exception of related party transactions, which are measured at the carrying amount determined in accordance with pre-changeover Canadian GAAP Section 3840, Related Party Transactions. Subsequent measurements are recorded at amortized cost using the effective interest rate method, if applicable.

(d) Property, plant and equipment

Property, plant and equipment include buildings and fixtures, land, furniture and equipment, rolling stock, electricity distribution infrastructure, and assets under construction.

Spare parts and standby equipment, which are expected to be used during more than one year, are considered to be assets under construction, and are depreciated only once they are put into service.

Property, plant and equipment are recorded at cost and include directly attributable contracted services, materials, labour, engineering costs, overheads and AFUDC. Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers. Contributions in aid of construction received are treated as a contra account to property, plant and equipment. The amount is depreciated by a charge to accumulated depreciation and a reduction in depreciation expense at an equivalent rate to that used for the depreciation of the related asset.

Significant renewals and enhancements to existing assets are capitalized only if the service life of the asset is increased, reliability is improved above original design standards or if operating costs are reduced by a substantial and quantifiable amount.

Depreciation is recorded on a straight-line basis over the estimated service life of the related asset.

Estimated service lives for property, plant and equipment classes are as follows:

Buildings and fixtures	20 to 75 years
Furniture and equipment	5 to 10 years
Rolling stock	7 to 15 years
Electricity distribution infrastructure	10 to 60 years

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(d) Property, plant and equipment [continued]

Land and assets under construction are not subject to depreciation.

The Company reviews its property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. If events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, the Company will estimate the future cash flows expected to result from the use of the asset group and their eventual disposition, and record an impairment loss, if required. The Company's primary measure of fair value is based on discounted cash flows.

(e) Intangible assets

Intangible assets include land rights, capital contributions and computer software.

Computer software is recorded at cost and includes directly attributable contracted services, materials, labour, overheads and AFUDC. Land rights and capital contributions are recorded at cost.

Intangible assets are amortized on a straight-line basis over the estimated service life of the related asset.

Estimated service lives for intangible assets are as follows:

Land rights	50 years
Capital contributions	45 years
Computer software	5 to 10 years

Assets which are not ready for use are not subject to amortization.

The Company reviews its intangible assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. If events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, the Company will estimate the future cash flows expected to result from the use of the asset group and their eventual disposition, and record an impairment loss, if required. The Company's primary measure of fair value is based on discounted cash flows.

(f) Asset retirement obligations

The Company recognizes its obligation to retire certain tangible long-lived assets, whereby the fair value of a liability for an asset retirement obligation is recognized in the period during which it is incurred if a reasonable estimate can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and then amortized over its estimated useful life. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows. The liability is adjusted for an annual accretion charged to operating costs. A gain or loss may be incurred upon settlement of the liability.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(g) Employee future benefits

(i) Pension plan

The Company provides pension benefits for its employees through the Ontario Municipal Employees Retirement System ['OMERS'] Fund [the 'Fund']. OMERS is a multi-employer pension plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a defined benefit pension plan, which is financed by equal contributions from participating employers and employees and by the investment earnings of the Fund.

Although the plan is a defined benefit plan, sufficient information is not available to the Company to account for it as such because it is not possible to attribute the fund assets and liabilities between the various employers who contribute to the fund. As a result, the Company accounts for the plan as a defined contribution plan, and contributions payable as a result of employee service are expensed as incurred as part of operating costs.

(ii) Employee future benefits other than pension plan

Employee future benefits other than pensions provided by the Company include life insurance benefits, accumulated sick leave credits and a retirement grant. These plans provide benefits to certain employees when they are no longer providing active service.

Employee future benefits expense is recognized in the period during which the employees render services.

Employee future benefits are recorded on an accrual basis. The accrued benefit obligation and current service costs are calculated using the projected unit credit method prorated on service and based on assumptions that reflect management's best estimates. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Actuarial gains and losses resulting from experience different from that assumed or from changes in actuarial assumptions are deferred as permitted by the OEB. In the absence of rate regulation, the actuarial gains and losses are included in the statement of income, comprehensive income and retained earnings.

(h) Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of construction obligations. Deposits estimated to be refundable to customers within the next fiscal year are classified as current liabilities and included in accounts payable and accrued liabilities.

(i) Leases

At the inception of a lease, or an arrangement that contains a lease, the Company evaluates whether the lease should be classified as a capital lease or an operating lease. Leases that transfer substantially all the risks and rewards incidental to ownership of the related asset are classified as capital leases. All other leases are classified as operating leases. Classification is reassessed if the terms of the lease are changed.

All of the Company's leases are classified as operating leases.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(j) Measurement uncertainty

The preparation of financial statements in conformity with pre-changeover Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets, liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements. Accounts receivable and unbilled revenue are reported net of an appropriate allowance for doubtful accounts ['AFDA']. Other significant estimates are used in determining the useful lives and asset impairments of long-lived assets, payments in lieu of corporate income taxes, employee future benefits, capital contribution obligations and certain accruals.

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the OEB or the provincial government. The financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant accounting policies.

3. FUTURE CHANGES IN ACCOUNTING POLICIES

On February 13, 2008, the Canadian Accounting Standards Board ['AcSB'] confirmed that publicly accountable enterprises ['PAEs'] would be required to transition to International Financial Reporting Standards ['IFRS'] effective January 1, 2011. While the Company is not a PAE, it is a Government Business Enterprise given its status as a municipally owned utility, and such enterprises are required to follow the same basis of accounting as PAEs.

On the original transition date, IFRS did not contain a standard governing rate-regulated activities ['RRA']. Due to the significance of this issue in Canada, the AcSB postponed the original IFRS transition date to January 1, 2015 for qualifying entities with RRA pending the completion of an interim standard by the International Accounting Standards Board ['IASB']. Until January 1, 2015, qualifying entities are permitted to continue reporting under pre-changeover Canadian GAAP.

On January 30, 2014, the IASB issued interim standard IFRS 14 – Regulatory Deferral Accounts ['IFRS 14'] which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices. This standard becomes effective January 1, 2016 with early adoption permitted. The Company has adopted IFRS and early adopted IFRS 14 on January 1, 2015. The Company has assessed the implications of adopting IFRS and is currently reviewing its impact on the financial reporting.

4. ACCOUNTS RECEIVABLE

		2014	2013
Electricity receivables, net of AFDA of $3,602 [2013 – $1,370] [Note 17.b]	**$**	**47,607**	$ 50,966
Other receivables, net of AFDA of $75 [2013 – $66] [Note 17.b]		**13,302**	9,757
Amounts due from related parties [Note 22]		**4,381**	5,668
	$	**65,290**	$ 66,391

5. UNBILLED REVENUE

		2014	2013
Unbilled revenue	$	**81,957**	$ 106,757
Less AFDA [Note 17.b]		**(151)**	(206)
	$	**81,806**	$ 106,551

6. REGULATORY ASSETS AND LIABILITIES

The Company files a rate application to settle its regulatory assets and liabilities as required. The time period for settlement is determined by the OEB based on the magnitude of the balances to be cleared.

Information about the Company's regulatory assets and liabilities is as follows:

		2014	2013
Regulatory assets			
OPEB deferral account [Note 12]	$	**4,432**	$ 3,109
Settlement variances		**12,224**	5,527
RARA		**208**	475
Other		**3,759**	3,361
		20,623	12,472
Less current portion		**(31)**	(31)
Total non-current regulatory assets	$	**20,592**	$ 12,441
Regulatory liabilities			
Settlement variances	$	**14,414**	$ 27,374
Stranded meters		**2,987**	-
Smart meters		**-**	1,045
RLRA		**3,143**	2,002
Other		**1,597**	1,667
		22,141	32,088
Less current portion		**-**	(19,173)
Total non-current regulatory liabilities	$	**22,141**	$ 12,915

6. REGULATORY ASSETS AND LIABILITIES [CONTINUED]

(a) Regulatory asset/liability refund accounts

The RARA/RLRA is the net aggregate of all regulatory assets and liabilities which have been approved for recovery or disposition and includes accrued interest costs up to December 31, 2014 of $174 [2013 – $178] less amounts already settled through distribution rates.

(b) Settlement variances

Settlement variances include accrued interest costs of $19 [2013 – $284].

(c) Other

Other variance and deferred costs include accrued interest earned of $48 [2013 – $34].

(d) Income before PILs

In the absence of rate regulation, the income before PILs for the year ended December 31, 2014 would be lower by $18,098 [2013 – lower by $13,052].

7. PROPERTY, PLANT AND EQUIPMENT

	2014		
	Cost	Accumulated depreciation	Net book value
Land	$ 24,995	$ -	$ 24,995
Buildings and fixtures	81,634	24,095	57,539
Furniture and equipment	12,970	6,803	6,167
Rolling stock	25,564	14,821	10,743
Electricity distribution infrastructure	1,201,880	447,516	754,364
Assets under construction	45,659	-	45,659
	1,392,702	493,235	899,467
Contributions in aid of construction	(256,647)	(54,336)	(202,311)
	$ 1,136,055	$ 438,899	$ 697,156

7. PROPERTY, PLANT AND EQUIPMENT [CONTINUED]

	2013		
	Cost	Accumulated depreciation	Net book value
Land	$ 24,995	$ -	$ 24,995
Buildings and fixtures	80,274	21,689	58,585
Furniture and equipment	17,970	11,768	6,202
Rolling stock	24,711	15,417	9,294
Electricity distribution infrastructure	1,131,821	437,739	694,082
Assets under construction	43,324	-	43,324
	1,323,095	486,613	836,482
Contributions in aid of construction	(233,023)	(48,118)	(184,905)
	$ 1,090,072	$ 438,495	$ 651,577

During the year, the Company capitalized an AFUDC of $1,286 [2013 – $1,295] to property, plant and equipment and credited financing costs [Note 18]. The average annual interest rate for 2014 was 4.6% [2013 – 4.5%].

During the year, the Company incurred a loss on disposal of property, plant and equipment of $1,890 [2013 – $989].

The Company entered into significant non-cash transactions that have been excluded from the statement of cash flows. These transactions were related to property, plant and equipment additions of $8,769 [2013 – $10,616], which represent amounts included in accounts payable and accrued liabilities at year end.

8. INTANGIBLE ASSETS

	2013	**Acquisitions (net of transfers)**	**Retirements**	**2014**
Cost				
Land rights	**$ 2,439**	**$ 11**	**$ -**	**$ 2,450**
Capital contributions	**3,162**	**637**	**-**	**3,799**
Computer software	**60,959**	**33,248**	**(29,410)**	**64,797**
Assets under development [Note 10]	**33,936**	**(5,561)**	**-**	**28,375**
	$ 100,496	**$ 28,335**	**$ (29,410)**	**$ 99,421**

8. INTANGIBLE ASSETS [CONTINUED]

	2013	Amortization	Retirements	2014
Accumulated amortization				
Land rights	**$ 661**	**$ 48**	**$ -**	**$ 709**
Capital contributions	**884**	**72**	**-**	**956**
Computer software	**54,218**	**5,671**	**(29,410)**	**30,479**
	$ 55,763	**$ 5,791**	**$ (29,410)**	**$ 32,144**

	Cost	Accumulated amortization	Net book value
Net book value as at December 31, 2014			
Land rights	**$ 2,450**	**$ 709**	**$ 1,741**
Capital contributions	**3,799**	**956**	**2,843**
Computer software	**64,797**	**30,479**	**34,318**
Assets under development [Note 10]	**28,375**	**-**	**28,375**
	$ 99,421	**$ 32,144**	**$ 67,277**

	2012	Acquisitions (net of transfers)	Retirements	2013
Cost				
Land rights	$ 2,437	$ 2	$ -	$ 2,439
Capital contributions	2,808	354	-	3,162
Computer software	64,065	2,159	(5,265)	60,959
Assets under development	13,690	20,246	-	33,936
	$ 83,000	$ 22,761	$ (5,265)	$ 100,496

	2012	Amortization	Retirements	2013
Accumulated amortization				
Land rights	$ 612	$ 49	$ -	$ 661
Capital contributions	830	54	-	884
Computer software	51,875	7,608	(5,265)	54,218
	$ 53,317	$ 7,711	$ (5,265)	$ 55,763

8. INTANGIBLE ASSETS [CONTINUED]

	Cost	Accumulated amortization	Net book value
Net book value as at December 31, 2013			
Land rights	$ 2,439	$ 661	$ 1,778
Capital contributions	3,162	884	2,278
Computer software	60,959	54,218	6,741
Assets under development	33,936	-	33,936
	$ 100,496	$ 55,763	$ 44,733

During the year, the Company capitalized an AFUDC of $571 [2013 – $1,081] to computer software and credited financing costs [Note 18]. The average annual interest rate for 2014 was 4.6% [2013 – 4.5%].

During the year, the Company incurred a loss on disposal of intangible assets of $174 [2013 – nil].

The Company entered into significant non-cash transactions that have been excluded from the statement of cash flows. These transactions were related to intangible asset additions of $17,182 [2013 – $729], which represent amounts included in accounts payable and accrued liabilities at year end.

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2014	2013
Purchased power payable	**$ 89,681**	$ 67,033
Trade payable and accrued liabilities	**34,966**	34,485
Capital contribution obligations [Note 10]	**15,700**	-
Customer deposits	**13,892**	14,306
Customer credit balances	**6,567**	7,364
Due to related parties [Notes 14 and 22]	**51,143**	56,177
	$ 211,949	$ 179,365

10. CAPITAL CONTRIBUTION OBLIGATIONS

The Company is party to various Connection and Cost Recovery Agreements ['CCRAs'] with HONI. These agreements govern the construction by HONI of new or modified transformer stations for the purpose of serving the Company's customers, including anticipated electricity load growth.

All terms and conditions of CCRAs follow the Transmission System Code [the 'Code'] issued by the OEB. The amount of the initial capital contribution required is based on the prescribed economic evaluation procedure set out in the Code. This initial capital contribution is reduced by any commitment of connection revenue [the 'guaranteed revenue'] earned by HONI from the Company over the period of the respective CCRA. Guaranteed revenue is calculated based on forecasted load ['initial load'] multiplied by HONI's approved rate at the time of entering into these agreements.

Each of the Company's CCRAs has a term 25 years. These agreements require periodic reviews whereby a comparison of actual to forecasted load is conducted, and a true-up calculation performed. When a true-up calculation shows the Company's actual load for the past period and updated load forecast for the future period is lower than the initial load

10. CAPITAL CONTRIBUTION OBLIGATIONS [CONTINUED]

forecast, the Company is obligated to make up this shortfall. When the Company's actual load and updated load forecast is higher than the initial load forecast, the Company is entitled to a rebate. True-up calculations are made in years 5 and 10 and in year 15 if the difference between the actual incremental load and initial load at the end of year 10 is greater than 20%.

Based on a review of the Company's CCRAs with HONI, the Company estimates a shortfall in guaranteed revenue. As a result of such a shortfall, the Company has recorded a total capital contribution obligation and a corresponding intangible asset of $15,700 as at December 31, 2014 (2013 – nil). The Company is expected to settle its capital contribution obligations in 2015.

11. ASSET RETIREMENT OBLIGATIONS

		2014	2013
Balance, beginning of year	**$**	**300**	$ 438
Liabilities settled during the year		**(104)**	(141)
Accretion expense		**-**	26
Revisions in estimated cash flows		**10**	(23)
	$	**206**	$ 300

As at December 31, 2014, the Company estimates an asset retirement obligation ['ARO'] of $206 [2013 – $300] related to the removal and destruction of polychlorinated biphenyls ['PCBs'] in distribution transformers and other clean-up related to PCBs. The ARO is calculated using an estimated undiscounted cash flow over two years [2013 – two years] totalling $254 [2013 – $357] and a discount rate of 5.3% [2013 – 5.3%]. No assets have been legally restricted for settlement of the liability.

12. EMPLOYEE FUTURE BENEFITS

(a) Pension plan

The Company's participating employer contributions under OMERS for the year ended December 31, 2014 amounted to $5,491 [2013 – $5,335].

(b) Employee future benefits other than pension plan

Employee future benefits are calculated using an annual compensation rate increase of 3.1% [2013 – 3.1%] and a discount rate of 4.0% [2013 – 4.8%] to calculate the liabilities. The valuation also includes several other economic and demographic assumptions including mortality rates. The mortality assumption is based on the Canadian Pensioners Mortality report published by the Canadian Institute of Actuaries in February 2014.

12. EMPLOYEE FUTURE BENEFITS [CONTINUED]

Information about the Company's defined benefit plans is as follows:

	2014		
	Accumulated liability	**Expense for the year**	**Benefits paid**
Life insurance	**$ 5,162**	**$ 508**	**$ 464**
Retirement grant	**909**	**89**	**107**
Sick Leave	**5**	**-**	**-**
	6,076	**$ 597**	**$ 571**
Deferred actuarial loss [Note 6]	**4,432**	**-**	**-**
	$ 10,508	**$ 597**	**$ 571**

	2013		
	Accumulated liability	Expense for the year	Benefits paid
Life insurance	$ 5,118	$ 481	$ 434
Retirement grant	927	83	21
Sick Leave	5	-	-
	6,050	$ 564	$ 455
Deferred actuarial loss [Note 6]	3,109	-	-
	$ 9,159	$ 564	$ 455

An actuarial valuation was performed as at December 31, 2014. As a result of this exercise, the Company increased the accumulated liability by $1,349 [2013 – decreased by $1,759 based on an actuarial extrapolation]. Changes in the accumulated actuarial loss are non-cash transactions that have been excluded from the cash flow statement.

The current liability portion of the accrued employee future benefits included in trade accounts payables and accrued liabilities amounts to $672 [2013 – $626] and the non-current portion was $9,836 [2013 – $8,533].

13. NOTES PAYABLE

The Company currently has the following promissory notes payable to Hydro Ottawa Holding Inc.:

- A $200,000 promissory note bearing interest at 5.04% per annum due February 9, 2015 [Note 23], unless otherwise agreed to by the two parties.

- A $50,000 promissory note bearing interest at 4.968% per annum due December 19, 2036, unless otherwise agreed to by the two parties.

- A $107,185 promissory note bearing interest at 4.144% per annum for the first five years [3.991% thereafter] due May 14, 2043, unless otherwise agreed to by the two parties.

The Company also has a grid promissory note facility with Hydro Ottawa Holding Inc. of which $60,000 is outstanding at December 31, 2014 [2013 – $30,000] [Note 23]. Interest on this note is fixed and is based on the cost of long-term debt for Ontario's Regulated Utilities in accordance with OEB's cost of capital calculations. Amounts outstanding on the grid promissory note are due on demand and Hydro Ottawa Holding Inc. has confirmed that it does not intend to recall any amounts on this note in 2015.

The promissory notes and the grid promissory note facility are subordinated and postponed to the obligation of the Company to a third party for the payment in full of any secured indebtedness and any and all security interests granted to secure such obligations of the Company.

		2014	2013
5.040% promissory note payable, re-issued May 14, 2013	**$**	**200,000**	$ 200,000
4.968% promissory note payable, issued May 14, 2013		**50,000**	50,000
4.144% promissory note payable, issued May 14, 2013		**107,185**	107,185
4.940% grid promissory note payable, issued December 10, 2013		**30,000**	30,000
5.770% grid promissory note payable, issued October 28, 2014		**30,000**	-
	$	**417,185**	$ 387,185

14. CREDIT FACILITY

The Company continues to maintain a $90,000 revolving demand credit facility and a $600 commercial card facility available from Hydro Ottawa Holding Inc. As at December 31, 2014, $49,000 [December 31, 2013 – $53,000] was drawn against the revolving demand credit facility via advances of $7,000 and $42,000 maturing on the 2nd and 5th of January, 2015, respectively. The rate of interest is based on the rate applicable to Hydro Ottawa Holding Inc.'s outstanding bankers' acceptances drawn on that date. Otherwise, the rate of interest is based on the Bank of Canada's 'Bankers Acceptances 1 month' rate. As at December 31, 2014 the rate of interest is based on Hydro Ottawa Holdings Inc.'s outstanding bankers' acceptances.

15. CAPITAL DISCLOSURES

The Company's main objectives when managing capital are to:

- Ensure continued access to funding to maintain and improve the operations and infrastructure of the Company;
- Ensure compliance with covenants related to the credit facilities and senior unsecured debentures entered into by its parent company, Hydro Ottawa Holding Inc.; and
- Align the Company's capital structure with the debt to equity structure recommended by the OEB.

The Company's capital consists of the following:

		2014		2013
Advances [Notes 14 and 22]	**$**	**49,000**	$	53,000
Notes payable [Notes 13 and 22]		**417,185**		387,185
Total debt		**466,185**		440,185
Shareholder's equity		**282,465**		269,594
Total capital	**$**	**748,650**	$	709,779
Debt capitalization ratio		**62 %**		62 %

The Company does not have any external debt arrangements as all financing is received from its parent company, Hydro Ottawa Holding Inc., which is in compliance with all financial covenants and limitations associated with its long-term debt.

The Company is deemed by the OEB to have a capital structure that is funded by 56% long-term debt, 4% short-term debt and 40% equity. The OEB uses this deemed structure only as a basis for setting distribution rates. As such, the Company's actual capital structure may differ from the OEB deemed structure.

The Company met its capital management objectives, which have not changed during the year.

16. SHARE CAPITAL

(a) Authorized

Unlimited number of voting first preferred shares, redeemable at one dollar per share
Unlimited number of non-voting second preferred shares, redeemable at ten dollars per share
Unlimited number of non-voting third preferred shares, redeemable at one hundred dollars per share
Unlimited number of voting [10 votes per share] fourth preferred shares, redeemable at one hundred dollars per share
Unlimited number of voting Class A common shares
Unlimited number of non-voting Class B common shares
Unlimited number of non-voting Class C common shares, redeemable at the price at which such shares are issued

The above shares are without nominal or par value.

Holders of second preferred shares, fourth preferred shares and common shares are entitled to receive dividends as and when declared by the Board of Directors at their discretion.

(b) Issued

		2014		2013
154,789,001 Class A common shares	**$**	**167,081**	$	167,081

Any invitation to the public to subscribe for shares of the Company is prohibited by shareholder resolution.

On April 3, 2014, the Board of Directors declared a $7,500 dividend on the common shares of the Company outstanding on December 31, 2013. The dividend was paid to the sole shareholder, Hydro Ottawa Holding Inc. on April 10, 2014 [2013 – April 4, 2013, the Board of Directors declared a $7,500 dividend which was paid on April 10, 2013].

On August 28, 2014, the Board of Directors declared a $7,500 dividend on the common shares of the Company outstanding on June 30, 2014. The dividend was paid to the sole shareholder, Hydro Ottawa Holding Inc. on September 4, 2014 [2013 – August 22, 2013, the Board of Directors declared a $7,500 dividend which was paid on September 5, 2013].

17. FINANCIAL INSTRUMENTS

(a) Carrying values

The Company's financial instruments consist of cash, accounts receivable, unbilled revenue, accounts payable and accrued liabilities, customer deposits, notes payable and capital contribution obligations. The only financial instrument recorded at fair value is cash and it is classified as level 1 in the pre-changeover Canadian GAAP Section 3862 fair value hierarchy. The carrying values of the Company's remaining financial instruments, except for notes payable, approximate fair value because of the short maturity of the instruments.

The Company has estimated the fair value of the notes payable as at December 31, 2014 as amounting to $438,300 [2013 – $399,000]. The fair value has been determined based on discounting all future payments of interest and the principal repayment on January 1, 2015, at the estimated interest rate of 3.5% [2013 – 4.0%] that would be available to the Company on December 31, 2014. The carrying value of the non-current portion of the capital contribution obligation is estimated using a discounted cash flow analysis based on the Company's projected borrowing rates, taking into account accrued interest on the outstanding balance.

(b) Risk factors

In the normal course of business, the Company is exposed to market risk, credit risk and liquidity risk. The Company's risk exposure and strategies to mitigate these risks are noted below.

(i) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market prices are comprised of three types of risks: interest rate risk, currency risk and other price risk such as equity risk.

The Company is exposed to interest rate risk on its borrowings. The Company mitigates exposure to interest rate risk by fixing interest rates on its notes payable with its parent company. Under Hydro Ottawa Holding Inc.'s credit facilities, any advances on its operating line would expose the Company to fluctuations in short-term interest rates related to prime rate loans and bankers' acceptances as all short-term financing requirements are obtained through its parent company, which passes on its borrowing costs. The interest rate risk is deemed to be low due to the immaterial cost of its short-term borrowings. For the most part, the borrowing requirements are for a very short duration as the advances serve to bridge gaps between the cash outflow related to the monthly power bill and the inflows related to the settlements with customers and, as such, there is very limited exposure to interest rate risk.

As at December 31, 2014, the Company has limited exposure to fluctuations in foreign currency exchange rates. The Company does purchase a small proportion of goods and services which are denominated in foreign currencies, predominately the US dollar. The impact of the fluctuation of foreign currencies on the gains or losses of accounts payable denoted in foreign currencies is not material.

As at December 31, 2014, the Company has not entered into any hedging transactions or derivative contracts.

17. FINANCIAL INSTRUMENTS [CONTINUED]

(b) Risk factors [continued]

(ii) Credit risk

Credit risk is the risk that a counterparty will default on its obligations, causing a financial loss. Concentration of credit risk associated with accounts receivable and unbilled revenue is limited due to the large number of customers the Company services. The Company has approximately 320,000 customers, the majority of which are residential. As a result, the Company did not earn a significant amount of revenue and does not have a significant receivable from any individual customer.

The Company performs ongoing credit evaluations of its customers and requires collateral to support non-residential customer accounts receivable on specific accounts to mitigate significant losses in accordance with OEB legislation. As at December 31, 2014, the Company held security deposits related to power recovery and distribution sales in the amount of $14,176 [2013 – $14,514].

The carrying amount of accounts receivable and unbilled revenue is reduced by an allowance for doubtful accounts based on the credit risk applicable to particular customers, and historical and other information. The Company records an allowance for doubtful accounts when the recoverability of an amount becomes doubtful. When the receivable amount is deemed to be uncollectible, it is written off and the allowance for doubtful accounts adjusted accordingly. Subsequent recoveries of receivables previously provisioned or written off result in a reduction of operating costs in the statement of income, comprehensive income and retained earnings. As at December 31, 2014, the allowance for doubtful accounts was $3,828 [2013 – $1,642]. During the year the Company implemented a new electricity billing system. The new billing system handles write-offs in a different manner by retaining the gross receivable balance on the books for a longer period before write-off occurs. As a result, management has increased the allowance for doubtful accounts. There is no impact on net receivables and the change did not affect the Company's overall credit risk.

17. FINANCIAL INSTRUMENTS [CONTINUED]

(b) Risk factors [continued]

(ii) Credit risk [continued]

Credit risk associated with accounts receivable and unbilled revenue is as follows:

		2014	2013
Total accounts receivable	**$**	**68,967**	$ 67,827
Total unbilled revenue		**81,957**	106,757
Less allowance for doubtful accounts		**(3,828)**	(1,642)
	$	**147,096**	$ 172,942
Of which			
Outstanding for 30 days or less		**52,085**	60,203
Outstanding for more than 30 days but not more than 120 days		**11,836**	5,665
Outstanding for more than 120 days		**5,046**	1,959
Unbilled revenue		**81,957**	106,757
Less allowance for doubtful accounts		**(3,828)**	(1,642)
	$	**147,096**	$ 172,942

As at December 31, 2014, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties and 24% [2013 – 11%] of the Company's accounts receivable was aged more than 30 days. The Company's maximum exposure to credit risk is equal to the carrying value of accounts receivable and unbilled revenue less deposits held.

(iii) Liquidity risk

Liquidity risk is the risk that the Company will not meet its financial obligations as they come due. The Company's parent, Hydro Ottawa Holding Inc., manages all the financing and investing activities for the Company. The Company has access to credit facilities with Hydro Ottawa Holding Inc. The liquidity risks associated with financial commitments relate to grid promissory notes, promissory notes or advances issued to/from its parent company, Hydro Ottawa Holding Inc., and accounts payable and accrued liabilities in the amount of $211,949 that are due within one year [2013 – $178,816].

The Company continues to have access to a $90,000 [2013 – $90,000] credit facility with Hydro Ottawa Holding Inc. as well as a $600 commercial card facility. As at December 31, 2014, the Company has drawn $49,000 [2013 – $53,000] [Note 14]. These credit facilities are available to the Company to help meet its financial obligations as they come due.

18. FINANCING COSTS

		2014	2013
Interest on notes payable	$	**18,743**	$ 17,507
Short-term interest		**836**	523
Financing charges		**151**	105
Less AFUDC		**(1,857)**	(2,376)
	$	**17,873**	$ 15,759

19. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rates. A reconciliation between the statutory and effective tax rates is provided as follows:

		2014	2013
Federal and Ontario statutory income tax rate		**26.50 %**	26.50%
Income before provision for PILS	$	**28,783**	$ 32,189
Provision for PILs at statutory rate	$	**7,627**	$ 8,530
Increase (decrease) resulting from			
Permanent differences		**24**	1,088
Regulatory offset to temporary differences and changes in future tax rates		**(6,347)**	(3,001)
Future tax benefit recognized on actuarial gains (losses) recorded in OPEB deferral account		**-**	495
Prior year adjustments		**(84)**	(58)
Tax credits		**-**	(162)
Other		**(308)**	(142)
	$	**912**	$ 6,750
Effective income tax rate		**3.17 %**	20.97 %

The Company, as a rate-regulated enterprise, is required to recognize future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates.

Provision for PILs consists of the following:

		2014	2013
Payments in lieu of corporate income taxes	$	**912**	$ 6,750
Future PILs corporate income tax provision			
Future income tax provision before regulatory adjustment		**8,641**	4,083
Regulatory adjustment for the recovery of future income tax provision		**(8,641)**	(4,083)
	$	**912**	$ 6,750

19. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES [CONTINUED]

The Company's future income tax assets are presented on the balance sheet as follows:

		2014		2013
Future income tax assets, current	**$**	**1,015**	$	818
Future income tax assets, non-current		**11,055**		19,893
	$	**12,070**	$	20,711

Significant components of the Company's future income tax assets are as follows:

		2014		2013
Property, plant and equipment and intangible assets	**$**	**6,574**	$	16,816
Employee future benefits		**3,789**		3,303
Other temporary differences		**1,707**		592
	$	**12,070**	$	20,711

The Company's regulatory liabilities for the amounts of future income taxes expected to be refunded to customers in future electricity rates are presented on the balance sheet as follows:

		2014		2013
Regulatory liability for future income tax assets, current	**$**	**1,015**	$	818
Regulatory liability for future income tax assets, non-current		**11,055**		19,893
	$	**12,070**	$	20,711

As at December 31, 2014, the Company had corporate minimum tax credits of $690 [2013 – nil], which expire in 2034.

20. CONTINGENT LIABILITIES

Purchasers of electricity in Ontario, including the Company, through the Independent Electricity System Operator ['IESO'], are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by a default notice issued by the IESO. A prudential support obligation is calculated based upon a default protection amount and the distributor's trading limit less a reduction for the distributor's credit rating. As at December 31, 2014, Hydro Ottawa Holding Inc. had drawn standby letters of credit in the amount of $8,150 [2013 – $16,000] against its credit facility to cover its prudential support obligation.

20. CONTINGENT LIABILITIES [CONTINUED]

The Company participates with other electrical utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electrical Association Reciprocal Insurance Exchange. The Company is liable for additional assessments to the extent premiums collected and reserves established are not sufficient to cover the cost of claims and costs incurred. If any additional assessments were required in the future, their cost would be charged to income in the year during which they occur.

In December 2012, the Company was charged with five charges under the Occupational Health and Safety Act in respect of an incident occurring on March 22, 2012, which resulted in the fatality of an employee of a third-party subcontractor. No charges have been or can be brought against directors, officers or employees arising from this incident. The maximum fine for each count is $500 plus a 25% Victim Fine Surcharge upon conviction. The Company, through external counsel, is defending the charges. At this time, it is not possible to quantify the effect, if any, of these changes on these financial statements.

Various lawsuits have been filed against the Company for incidents that arose in the ordinary course of business. In the opinion of management, the outcomes of the lawsuits, now pending, are neither determinable nor material. Should any loss result from the resolution of these claims, such losses would be claimed through the Company's insurance carrier, with any unrecoverable amounts charged to income in the year of resolution.

21. COMMITMENTS

The Company has $58,854 in total open commitments for 2015 to 2022. This includes commitments relating to a customer information system services agreement, construction projects, spare parts and standby equipment, and overhead and underground services.

22. RELATED PARTY TRANSACTIONS

The Company is wholly owned by Hydro Ottawa Holding Inc., which in turn is wholly owned by the City of Ottawa. Hydro Ottawa Holding Inc. is also the sole shareholder of Energy Ottawa Inc. Chaudiere Hydro L.P. is wholly owned by Energy Ottawa Inc.

The following table provides the transactions entered into with related parties as well as outstanding balances at year end. These transactions occur in the normal course of business, and are transacted at the amount of consideration determined and agreed to by the related parties.

Trade amounts due from and to Hydro Ottawa Holding Inc. and Energy Ottawa Inc. are non-interest bearing and due on demand.

22. RELATED PARTY TRANSACTIONS [CONTINUED]

	2014 Transactions during the year		2014 Balances at year end	
	Sales to related parties	Purchases from related parties	Due from related parties	Due to related parties
City of Ottawa and subsidiaries				
Sale of electricity [1]	$ 44,008	$ -	$ -	$ -
Other services [2]	7,499	-	-	-
Fuel, permits and other services [3]	-	918	-	-
Property taxes [3]	-	2,165	-	-
Conservation and demand management [3]	-	283	-	-
Accounts receivable	-	-	4,335	-
Accounts payable and accrued liabilities	-	-	-	53
	$ 51,507	$ 3,366	$ 4,335	$ 53
Hydro Ottawa Holding Inc.				
Administrative and corporate support services [2] [3]	$ 779	$ 3,360	$ -	$ -
Financing [4]	24	151	-	-
Interest [4]	-	19,579	-	-
Accounts payable and accrued liabilities	-	-	-	50,290
Notes payable	-	-	-	417,185
	803	23,090	-	467,475
Energy Ottawa Inc.				
Purchase of electricity [5]	-	3,569	-	-
Conservation and demand management initiatives [3]	-	971	-	-
Administrative and corporate support services [2]	976	-	-	-
Accounts payable and accrued liabilities	-	-	-	800
	976	4,540	-	800
Chaudiere Hydro L.P.				
Accounts receivable	-	-	46	-
Total	$ 53,286	$ 30,996	$ 4,381	$ 468,328

[1] Included in power recovery, distribution sales and regulatory assets/liabilities
[2] Included in other revenue and contributions in aid of construction
[3] Included in operating costs and property, plant and equipment
[4] Included in financing costs
[5] Included in purchased power

22. RELATED PARTY TRANSACTIONS [CONTINUED]

	2013 Transactions during the year		2013 Balances at year end	
	Sales to related parties	Purchases from related parties	Due from related parties	Due to related parties
City of Ottawa and subsidiaries				
Sale of electricity [1]	$ 39,908	$ -	$ -	$ -
Other services [2]	7,684	-	-	-
Fuel, permits and other services [3]	-	1,183	-	-
Property taxes [3]	-	2,053	-	-
Conservation and demand management initiatives [3]	-	57	-	-
Accounts receivable	-	-	5,608	-
Accounts payable and accrued liabilities	-	-	-	222
	47,592	3,293	5,608	222
Hydro Ottawa Holding Inc.				
Administrative and corporate support services [2] [3]	771	3,623	-	-
Financing [4]	59	105	-	-
Interest [4]	-	17,971	-	-
Accounts payable and accrued liabilities	-	-	-	54,893
Notes payable	-	-	-	387,185
	830	21,699	-	442,078
Energy Ottawa Inc.				
Purchase of electricity [5]	-	2,832	-	-
Conservation and demand management initiatives [3]	-	1,211	-	-
Administrative and corporate support services [2]	1,015	-	-	-
Accounts payable and accrued liabilities	-	-	-	1,062
	1,015	4,043	-	1,062
Chaudiere Hydro L.P.				
Accounts receivable	-	-	60	-
Total	$ 49,437	$ 29,035	$ 5,668	$ 443,362

[1] Included in power recovery, distribution sales and regulatory assets/liabilities
[2] Included in other revenue and contributions in aid of construction
[3] Included in operating costs
[4] Included in financing costs
[5] Included in purchased power

23. SUBSEQUENT EVENTS

On February 9, 2015, the Company repaid to Hydro Ottawa Holding Inc. a $200,000 promissory note and a grid promissory facility of which $60,000 was outstanding at December 31, 2014. The repayments were accomplished through the issuance of a new $138,667 10-year promissory note bearing interest at 2.724% for the first 5 years and 2.614% thereafter per annum due February 3, 2025 and a new $121,333 30-year promissory note bearing interest at 3.769% for the first 5 years and 3.639% thereafter per annum due February 2, 2045, both payable to Hydro Ottawa Holding Inc. The promissory notes are subordinated and postponed to the obligation of the Company to a third party for the payment in full of any secured indebtedness and any and all security interests granted to secure such obligations of the Company.

24. COMPARATIVE FIGURES

In certain instances, the 2013 information presented for comparative purposes has been reclassified to conform to the financial statement presentation adopted for the current year.

RECONCILLIATION OF 2012, 2013 and 2014 AUDITED FINANCIAL STATEMENTS

The reconciliations of Hydro Ottawa Limited's 2012, ~~and~~ 2013 and 2014 audited Financial Statements are attached as Attachment A-4(F), ~~and~~ A-4(G) and A-4(H) respectively. ~~The 2014 reconciliation will be filed as Attachment A-4(H) when available.~~

RECONCILLIATION OF AUDITED FINANCIAL STATEMENTS AND APPLICTION

The following tables reconcile Hydro Ottawa Limited's ("Hydro Ottawa") 2014 Audited Financial Statements to Information for the Historical Year (2014) that is provided in this Application

Table 1 – Statement of Income

Statement of Income	CGAAP Audited 2014 ($'000)	MIFRS adjustment (1) ($'000)	Unregulated Business (2) (3) ($'000)	2014 Regulated Balances (2) (3) ($'000)
REVENUES				
Power recovery	$ 799,272	$ -	$ -	$ 799,272
Distribution sales	156,616	-	-	156,616
Other revenue	32,554	-	(20,317)	12,237
TOTAL REVENUES	988,442	-	(20,317)	968,125
EXPENSES				
Purchased power	799,272	-	-	799,272
Operating costs	106,474	54	(20,321)	86,208
Amortization/Depreciation	36,040	(249)	(102)	35,689
OTHER				
Financing costs	17,873		-	17,873
PILS	912	(4)	-	908
TOTAL EXPENSE	**960,571**	**(198)**	**(20,423)**	**939,949**
NET INCOME	**27,871**	**198**	**106**	**28,175**

[1] Net book value for capital assets and depreciation are different between CGAAP and MIFRS due to different capitalization policies between CGAAP and MIFRS prior to January 1, 2012. Capitalization policies under both accounting standards have been aligned starting January 1, 2012.
[2] For the purposes of this rate application, and in accordance with Ontario Energy Board policies, all revenue and expenses associated with Conservation and Demand Management ("CDM") has been excluded from the costs and revenues in this rate application. In addition, revenues and expenses related to other non-utility operations, such as rental of properties not in rate base, have also been excluded.
[3] For financial statement purposes interest earned (Account 4405) is an offset to interest expense (and in other revenue for regulatory accounting) and certain short-term interest is recorded as an operating expense.
[4] Remove Non-Utility Assets
[5] Adjustment includes reclassification differences between CGAAP and MIFRS between Properties, plant and equipment, Intangible, Investment properties and deferred income

The following table provides a reconciliation of Capital Assets as reported in the 2014 Audited Financial Statement and the information on the Historical Year (2014) that is provided in this Application.

Table 2 – Capital Assets

	CGAAP Audited 2014 ($'000)	MIFRS adjustment (1) (5) ($'000)	Unregulated Business (4) ($'000)	2014 Regulated Balances ($'000)
Property, plant and equipment	$ 697,156	$ 91,840	$ (318)	**$ 788,678**
Intangible assets	67,277	(1,069)	-	**66,208**
Investment properties	-	2,172	(2,172)	**-**
Deferred income	-	(93,492)	-	**(93,492)**
TOTAL	**$ 764,433**	**$ (549)**	**$ (2,490)**	**$ 761,394**

[1] Net book value for capital assets and depreciation are different between CGAAP and MIFRS due to different capitalization policies between CGAAP and MIFRS prior to January 1, 2012. Capitalization policies under both accounting standards have been aligned starting January 1, 2012.
[2] For the purposes of this rate application, and in accordance with Ontario Energy Board policies, all revenue and expenses associated with Conservation and Demand Management ("CDM") has been excluded from the costs and revenues in this rate application. In addition, revenues and expenses related to other non-utility operations, such as rental of properties not in rate base, have also been excluded.
[3] For financial statement purposes interest earned (Account 4405) is an offset to interest expense (and in other revenue for regulatory accounting) and certain short-term interest is recorded as an operating expense.
[4] Remove Non-Utility Assets
[5] Adjustment includes reclassification differences between CGAAP and MIFRS between Properties, plant and equipment, Intangible, Investment properties and deferred income

ANNUAL REPORT AND MANAGEMENT DISCUSSION AND ANALYSIS

Hydro Ottawa Holding Inc.'s (i.e. Hydro Ottawa Limited's parent company) Annual Report and Management's Discussion and Analysis for 2013 can be found in the subsequent attachment, A-4(C). Hydro Ottawa Holding Inc.'s Annual Report and Management's Discussion and Analysis for 2014 can be found in the new subsequent attachment, A-4(I).

HydroOttawa Holding Inc.

2014 Annual Report




Cover:

Hydro Ottawa believes that a workforce that is reflective of the diversity of the communities we serve provides us with a better understanding of the needs of our customers, and that by cultivating an inclusive culture that leverages diversity, we enhance employee engagement and innovation. Increasing the number of women working in trades and technical occupations at Hydro Ottawa is important to us. Hydro Ottawa is proud of its employees from left to right who occupy Field Operator, Professional Engineer, Stations Technician and Apprentice Stations Electrician positions.

Our Mission

Hydro Ottawa's mission is to create long-term value for our shareholder, benefiting our customers and the communities we serve.

Hydro Ottawa is both a community asset and an investment for our shareholder, the City of Ottawa. As a community asset, our goal is to provide effective, efficient and reliable service to our customers, and to be a strong strategic partner for our city, helping to deliver on its economic development and environmental agendas. As an investment, our goal is to provide stable, reliable and growing returns to our shareholder.

Table of Contents

Company Profile

Hydro Ottawa Holding Inc., (Hydro Ottawa) is 100 percent owned by the City of Ottawa. It is a private company, registered under the *Ontario Business Corporations Act*, and overseen by an independent board of Directors consisting of 11 members appointed by City Council. The core businesses of the Corporation are electricity distribution, renewable energy generation and related services. In 2014, Hydro Ottawa owned and operated two subsidiary companies.

Hydro Ottawa Limited

Hydro Ottawa Limited is a regulated electricity distribution company operating in the City of Ottawa and the Village of Casselman. As the third-largest municipally owned electrical utility in Ontario, Hydro Ottawa Limited maintains one of the safest, most reliable and cost-effective electricity distribution systems in the province, and serves over 320,000 residential and commercial customers across a service area of 1,100 square kilometres. As a condition of its distribution license, the company is required to meet conservation and demand management targets established by the Ontario Energy Board. Hydro Ottawa Limited added approximately 5,000 new customers to its distribution system in 2014, an increase of 1.6 percent, while the volume of electricity delivered through its distribution network decreased by approximately 0.9 percent over the prior year. The company's capital assets grew by $68 million, or 9.8 percent.

Energy Ottawa Inc.

Energy Ottawa is the largest municipally owned producer of green power in Ontario, and a provider of commercial energy management services. It owns and operates six run-of-the-river hydroelectric generation plants at Chaudière Falls in the city's core and holds interests in two landfill gas-to-energy joint ventures that convert millions of tonnes of previously flared-off methane gas into renewable energy at the Trail Road landfill site in Ottawa and the Laflèche landfill site in Moose Creek, Ontario. In total, this represents a generation capacity of more than 48 megawatts annually, which is enough to power 40,000 homes. Energy Ottawa has also embarked on a multi-year project to expand its Ontario generation facilities at Chaudière Falls with the expanded generation production capacity expected in the fourth quarter of 2017. This expansion will increase Energy Ottawa's total capacity from 48 megawatts to 68 megawatts.

Message from the Chair of the Board, and President and Chief Executive Officer

On behalf of management and the Board of Directors of both Hydro Ottawa Holding Inc. and Hydro Ottawa Limited, and our more than 650 dedicated employees – we are very pleased to provide this 2014 Annual Report to our shareholder, the City of Ottawa.

Jim Durrell, C.M., Chair, Board of Directors, and Bryce Conrad, President and Chief Executive Officer, at the 14th Annual Hydro Ottawa Special Needs Day, where more than 1,000 children with mental and physical challenges enjoyed exclusive access to the Capital Fair thanks to Hydro Ottawa employee volunteers

This report marks the third year of reporting against our *2012-2016 Strategic Direction*, which was endorsed by our shareholder in June 2012. Hydro Ottawa's mission over the term of that five-year plan is to deliver value, both as a community asset providing essential services to our customers, and as an investment for the City of Ottawa, our shareholder. With that mission in mind, our goal is two-fold: to continue to fulfil our core mandate to provide a safe, reliable, affordable and sustainable supply of electricity to the over 320,000 homes and businesses that rely on us every day; and to ensure a more sustainable energy future for our community.

In 2014, Hydro Ottawa continued to provide value to our shareholder. We advanced key elements of our business strategy, while once again achieving strong financial results that exceeded our targets for the year. This is a reflection of our focus on our four critical areas of performance that form the foundation of our strategic plan – financial strength, customer value, organizational effectiveness, and corporate citizenship.

In the area of financial strength, Hydro Ottawa's 2014 net income of $30.3 million surpassed the strategic plan projection by $3.3 million, resulting in $18.2 million in dividends to the City of Ottawa. With strong performance in 2012, 2013 and 2014, Hydro Ottawa has delivered $56.1 million of the $90 million dividend commitment set out in the *2012-2016 Strategic Direction*. Based on this record of performance and prudent management of business risks, Hydro Ottawa continued to maintain its "A" credit rating with a "Stable" trend in 2014.

Hydro Ottawa's strong financial performance for 2014 was achieved in large part through our continued focus on cost controls and enhanced revenues in our renewable energy generation business. Revenues from renewable generation for 2014 were nearly $20 million from its six run-of-the-river hydroelectric plants at Chaudière Falls, and its landfill gas-to-energy facilities at the Trail Road landfill site in Ottawa and at the Laflèche landfill site in Moose Creek, Ontario.

While Hydro Ottawa Limited, our regulated electricity distribution company, continued to be the largest contributor to our net income, electricity consumption continued to drop, while costs increased.

Revenue growth in the electricity distribution business is not expected to keep pace with cost increases arising from customer growth, contractual and inflationary pressures, as well as changing regulatory requirements. Productivity improvement is a must to partially offset rising costs, and enhanced revenue growth from our renewable generation business will be critical to increasing shareholder value. That is why Hydro Ottawa continued to pursue business growth opportunities in 2014. In addition to being awarded a 40-year power purchase agreement by the Ontario Power Authority that will see the expansion of our renewable generation capacity at Chaudière Falls by over 50 percent, we also secured contracts for 2.3 megawatts of solar rooftop capacity from the Ontario Power Authority. Working with our shareholder, the City of Ottawa, we will be proceeding with eight solar rooftop installation projects in 2015 on City-owned facilities. The installations are estimated to generate 3,226 MWh/year – enough electricity to power 336 homes for a year.

Our *2012-2016 Strategic Direction* calls for a continued focus on enhancing customer value and that is why working to keep distribution rates stable for the more than 320,000 homes and businesses we serve remains a priority. While the overall customer bill increased in 2014, the approved distribution rate increase for the Hydro Ottawa portion was 1.4 percent effective January 1, 2014.

We also continued to make significant investments in service reliability. Like all utilities in Ontario, Hydro Ottawa must replace aging distribution system equipment at an accelerated pace. We are investing more than half a billion dollars over the course of our 2012-2016 plan to improve system reliability and reduce the occurrence of interruptions caused by aging and defective equipment.

Hydro Ottawa's reliability performance was noticeably improved in 2014 after several years of challenges due to episodes of bad weather as well as increasing failure rates for aging distribution assets. Our overall investment in electricity distribution assets was upward of $125.6 million, including the $8.3 million expansion of the Limebank transformer station to better serve the growing communities of Riverside South and Barrhaven.

Achieving our goals for customer and shareholder value requires a high performance workforce, and efficient and effective operations. At Hydro Ottawa, we strive for performance excellence in every area of our operations.

In light of shifting demographic trends, anticipated retirements and changing skill requirements, we continued to plan and prepare both for continuity of skilled trades and technical capacity, and management succession to ensure a prepared and sustainable workforce over the next five to ten years. Key initiatives in this regard included the continuation of our skilled trades apprenticeship programs, our engineering internship program and our development and performance management programs, the designation of our Algonquin College Powerline Technician Diploma Program partnership as the primary pool for co-op and apprentice candidates, and the launch of our Diversity Plan.

Hydro Ottawa also continued to be a responsible and engaged corporate citizen. In 2014, we renewed our partnership with Christie Lake Kids (CLK) and sponsored both the Hydro Ottawa Sustainable Youth Leadership Centre and the CLK 'Skills through Activity and Recreation' (STAR) Hockey and Skating Program. We also established the Hydro Ottawa STAR Cup. And our United Way fundraising efforts raised a record $254,427 in 2014, bringing our 14-year total to more than $1.75 million. Whether by helping our customers conserve energy, greening our operations, educating over 17,000 local elementary students about electricity safety and conservation, or providing nearly $170,000 in financial assistance to front-line agencies that serve people who are homeless or at risk of being homeless through our Brighter Tomorrow's Fund, Hydro Ottawa was there.

As a result of the company's achievements, Hydro Ottawa was recognized once again in 2014 by a number of awards including among others, for the sixth year in a row as one of the National Capital Region's Top Employers, for the fourth year in a row as one of Canada's Greenest Employers, and by the Best Ottawa Business Awards (the BOBS) as Sustainability Leader of the Year. We also had the enviable distinction of being honoured as one of Canada's Top Employers for Young People and by the Best Employers Award for 50 Plus Canadians in recognition of our program to engage experienced workers and retirees.

We are proud of the company's achievements and contributions in 2014 and sincerely thank our employees for their ongoing hard work and dedication. We look forward to advancing our *2012-2016 Strategic Direction* and continuing to deliver value in the years ahead.

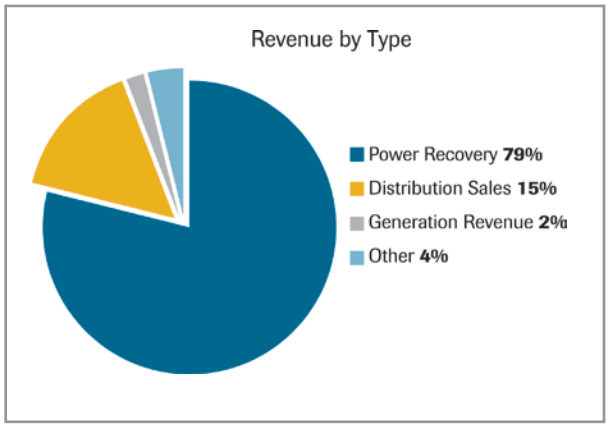
Sincerely,

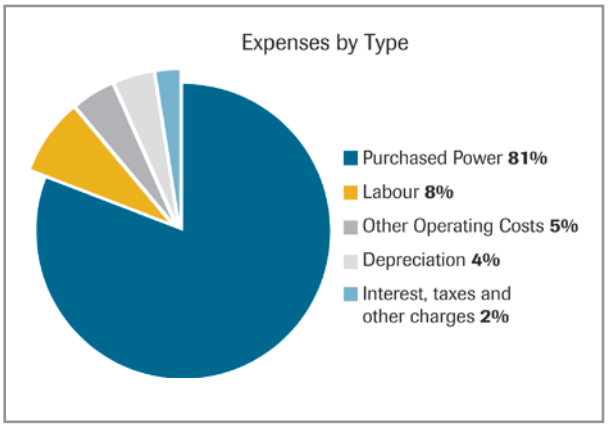
Jim Durrell, C.M.
Chair, Board of Directors

Bryce Conrad
President and Chief Executive Officer

Financial Highlights

(in thousands of Canadian dollars)	2014	2013
Operations		
Total revenue	1,012,349	976,367
Distribution revenue	156,616	152,392
Generation revenue	19,617	21,047
EBITDA	93,388	96,925
Net income	30,318	32,142
Dividends	(18,200)	(19,300)
Balance Sheet		
Total assets	1,060,293	1,008,556
Capital assets	867,199	791,782
Long-term debt	403,208	400,413
Shareholder's equity	398,071	384,153
Cash Flows		
Operating	108,614	49,430
Investing	(101,145)	(112,184)
Financing	(14,571)	131,258





Progress Against Plan

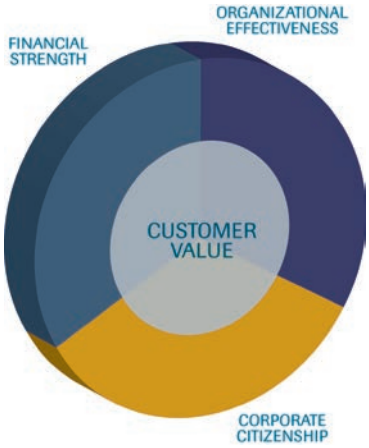
Hydro Ottawa's 2014 Annual Report is the third to report against the company's *2012-2016 Strategic Direction: Creating Long-Term Value*.

The aim of the Strategic Direction is to move the company from 'good to great', leveraging our position as a leading and trusted service provider to become one of Canada's most successful integrated utilities.

This strategy is built on the company's strengths and achievements, and responds to a changing environment that presents significant opportunities for Hydro Ottawa and the community we serve.

To ensure we take full advantage of those opportunities, Hydro Ottawa is focused on the fundamentals of leading performance: Financial Strength, Customer Value, Organizational Effectiveness, and Corporate Citizenship. These four Key Areas of Focus guide our business strategy and form the basis of our annual reporting in the pages that follow.

One of our Key Areas of Focus — Customer Value — takes on central importance under the company's five-year plan. The essence of Hydro Ottawa's business strategy is to put the customer at the centre of everything we do.



FOUR KEY AREAS OF FOCUS

Financial Strength

STRATEGIC OBJECTIVE

We will create sustainable growth in our business and our earnings

By improving productivity and pursuing business growth opportunities that leverage our strengths — our core capabilities, our assets and our people

Customer Value

STRATEGIC OBJECTIVE

We will deliver value across the entire customer experience

By providing reliable, responsive and innovative services at competitive rates

Organizational Effectiveness

STRATEGIC OBJECTIVE

We will achieve performance excellence

By cultivating a culture of innovation and continuous improvement

Corporate Citizenship

STRATEGIC OBJECTIVE

We will contribute to the well-being of the community

By acting at all times as a responsible and engaged corporate citizen

Financial Strength

Strategic Objective: We will create sustainable growth in our business and our earnings by improving productivity and pursing business growth opportunities that leverage our strengths — our core capabilities, our assets and our people.

Our commitment is to provide sustained shareholder value now and in the future.

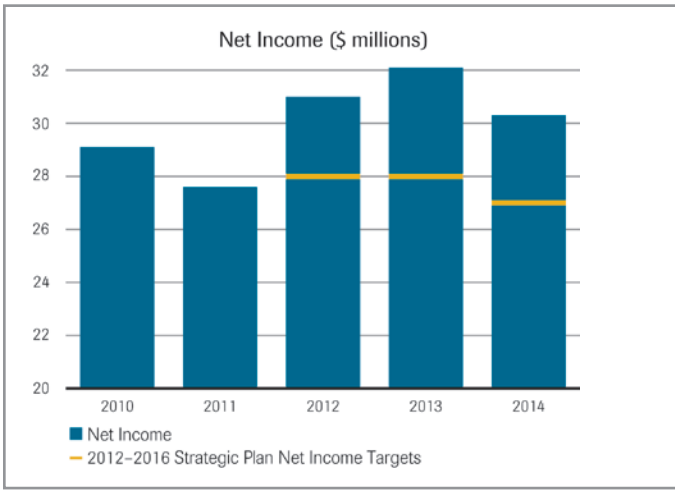
For a third consecutive year, Hydro Ottawa exceeded its financial targets as set out in our *2012-2016 Strategic Direction*. This continued to be due in large part to our focus on cost containment and strong performance in our renewable energy generation business line that has enhanced the company's ability to fulfil our core mandate to provide a safe, reliable, affordable and sustainable supply of electricity to the more than 320,000 homes and businesses that rely on us every day.

We exceeded our financial targets

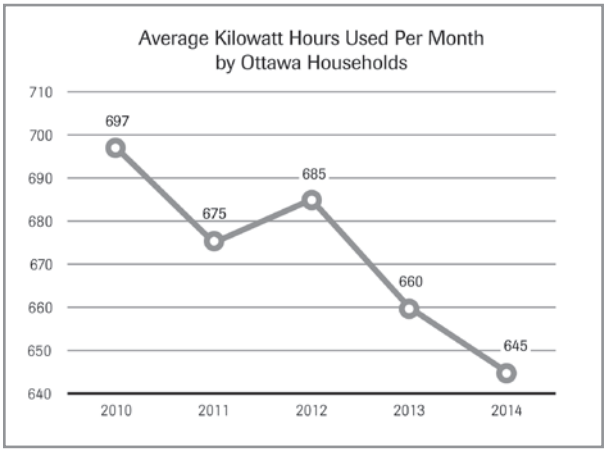
Hydro Ottawa's net income in 2014 was $30.3 million, exceeding the target forecast in the 2012-2016 Strategic Direction by $3.3 million. Cumulative net income for 2012 to 2014, the first three years of our five-year Strategic Direction, has exceeded target by $10.4 million.

While our regulated local distribution company, Hydro Ottawa Limited, continued to be the largest contributor to our net income, electricity consumption continued to drop, while costs increased.

In order to manage these pressures, Hydro Ottawa maintained its focus on cost control and productivity. One important indicator of productivity is operating cost per customer. Each year the Ontario Energy Board (OEB) compares the operating costs per customers of all Ontario electricity distributors. In the OEB's most recent yearbook, Hydro Ottawa ranked 15th out of 73 distribution companies in terms of lowest costs per customer.



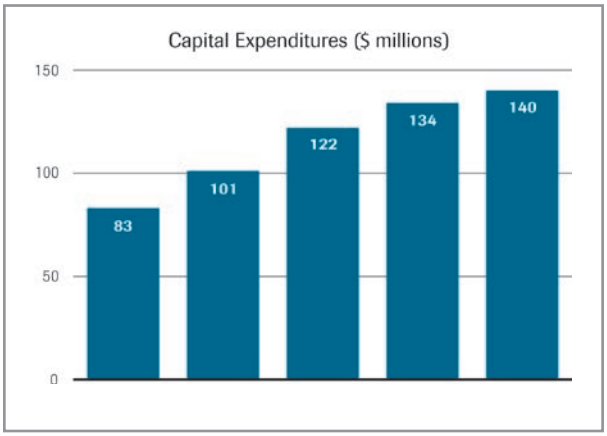
$30.3 million in net income



Hydro Ottawa's renewable energy generation business line earned nearly $20 million in revenue in 2014 from its six run-of-the-river hydroelectric plants at Chaudière Falls, and its landfill gas-to-energy facilities at the Trail Road landfill site in Ottawa and at the Laflèche landfill site in Moose Creek, Ontario.

We continued to make significant investments in our infrastructure

In 2014, Hydro Ottawa invested $140 million in our electricity distribution system and generation assets – part of our plan to make significant investments over the course of our *2012-2016 Strategic Direction* to maintain and enhance reliability, and to address aging infrastructure and system growth.



$140 million capital program

The landfill gas-to-energy plant at the Trail Road landfill site hit its highest ever production level in 2014, resulting in a record royalty payment of $192K to the City

$8.3M Limebank transformer station upgrade

$7M invested in generation asset sustainment including rebuilding the bulkhead at the Bronson Channel

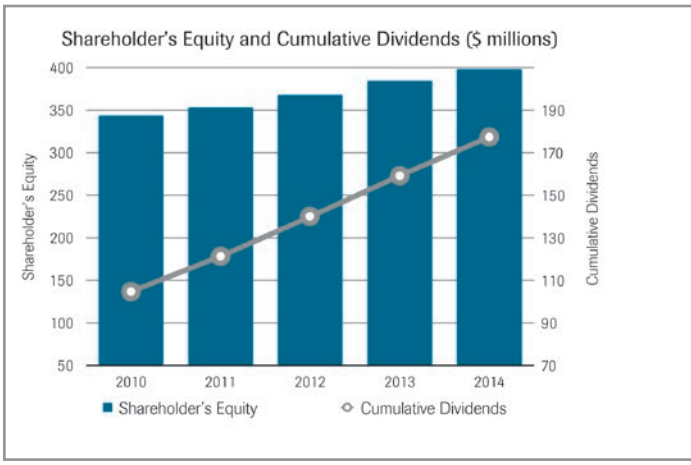
Shareholder value increased by 10%

Hydro Ottawa continued to provide excellent value to its shareholder in 2014, with a return on equity of 7.8 percent. Total shareholder value – including dividends paid and earnings retained with the company – increased 10 percent during the year.

Since 2005, Hydro Ottawa has delivered $177.4 million in dividends to the City of Ottawa, including $18.2 million arising from 2014 results.

With strong performance from 2012 through 2014, Hydro Ottawa has delivered $56.1 million of the $90 million dividend commitment set out in the 2012-2016 Strategic Direction.

Based on this record of strong operational performance and prudent management of business risks, Hydro Ottawa continued to maintain its "A" credit rating with a "Stable" trend in 2014.



$18.2 million in dividends to the City of Ottawa

We also continued to pursue business growth opportunities

To enhance the company's ability to respond to changing needs and expectations, and to ensure long-term financial sustainability, Hydro Ottawa continued to pursue business growth opportunities. In 2014, Hydro Ottawa was awarded a forty-year power purchase agreement by the Ontario Power Authority that allowed us to proceed with the expansion of our renewable generation capacity at Chaudière Falls. This will see the construction of a new 29-megawatt generation facility, which will increase our hydroelectric generation capacity by 50 percent. Construction is to begin in 2015.

We also secured contracts for 2.3-megawatts of solar rooftop capacity from the Ontario Power Authority. Working with our shareholder, the City of Ottawa, we will be proceeding with eight solar rooftop installation projects in 2015 on City-owned facilities including the Articulated Bus Garage, Walter Baker Sports Centre, and the Kanata Recreation Complex. The installations are estimated to generate 3,226 MWh/year – enough electricity to power 336 homes for a year.

Ring Dam at Chaudière Falls

Rooftop Solar Panels at Ottawa City Hall

Customer Value

Strategic Objective: We will deliver value across the entire customer experience by providing reliable, responsive and innovative services at competitive rates.

The essence of Hydro Ottawa's business strategy is to put the customer at the centre of everything we do. Understanding and responding to the customer's needs and expectations—for quality service, cleaner energy, and help in controlling their energy consumption and electricity costs—is the key to success in an evolving energy landscape.

We strive to deliver a reliable product while keeping our service efficient and friendly and our rates as low as possible.

Customer satisfaction remained strong

Overall customer satisfaction remained strong at 83 percent. This was slightly lower than in previous years primarily due to external industry events.

83 percent customer satisfaction rate

We kept our focus on improving the customer's experience

Hydro Ottawa completed a smooth transition to monthly billing for our customers in 2014 and continued to promote customer self-serve and paperless billing and payment options; by year end, more than 122,000 of our customers were subscribed to MyHydroLink, while nearly 86,000 had signed up for e-billing.

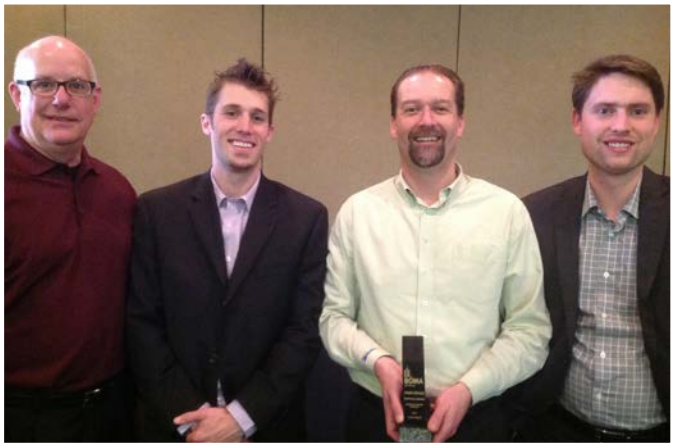
We continued to support our customers and other stakeholders on a variety of social media platforms including Twitter, Facebook, YouTube and LinkedIn—part of our plan to communicate with customers on their own terms—when and how they want. Our Twitter followers increased by 53 percent over the prior year.

Hydro Ottawa is an e-billing adoption leader among industry peers in Ontario

We continued to help people conserve and control their electricity costs

Hydro Ottawa continued to be a leader in promoting energy conservation in our community, helping residents and businesses use our product efficiently and wisely.

It was another excellent year for Small Business Lighting with 2,400 small businesses taking advantage of professionally installed energy efficient lighting. Another 750 larger commercial customers took advantage of our retrofit program trade to much more efficient energy systems.



Hydro Ottawa's Conservation and Demand Management (CDM) team was recognized for providing exceptional customer service to its commercial customers with a Pinnacle Award from the Building Owners and Managers Association (BOMA) of Ottawa

Our Energy Services team also completed a number of retrofits to LED technologies for City of Ottawa services, notably for 700 street light fixtures on Carling Avenue and 8 OC Transpo Stations, as well as for 30 Ottawa Community Housing buildings.

The offer of a free programmable thermostat for participation in the *peaksaver*PLUS program was discontinued in 2014. There are now more than 37,000 households participating in the program.

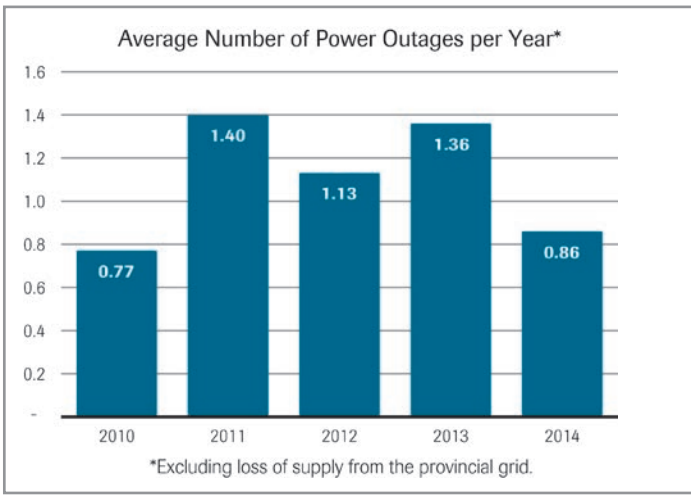
More than 50 GWh saved from our residential, small business and large commercial conservation programs – enough electricity to power 6,000 homes for a year

Hydro Ottawa joined Ottawa Senators President, Cyril Leeder, Ontario Minister of Energy, Bob Chiarelli and Hydro Ottawa Chair, Jim Durrell, in announcing a state-of-the-art LED lighting upgrade at the Canadian Tire Centre on November 28

A reliable supply of electricity remained our top priority

Hydro Ottawa's reliability performance was noticeably improved in 2014 after several years of challenges due to episodes of bad weather as well as increasing failure rates for aging distribution assets.

Like most utilities in Ontario, Hydro Ottawa faces a need to replace aging distribution system equipment at an accelerated pace. Our plan is to continue to make significant investments of more than half a billion dollars over the course of our 2012-2016 Strategic Direction to achieve the maximum benefit for our customers and reduce the occurrence of interruptions caused by defective equipment.

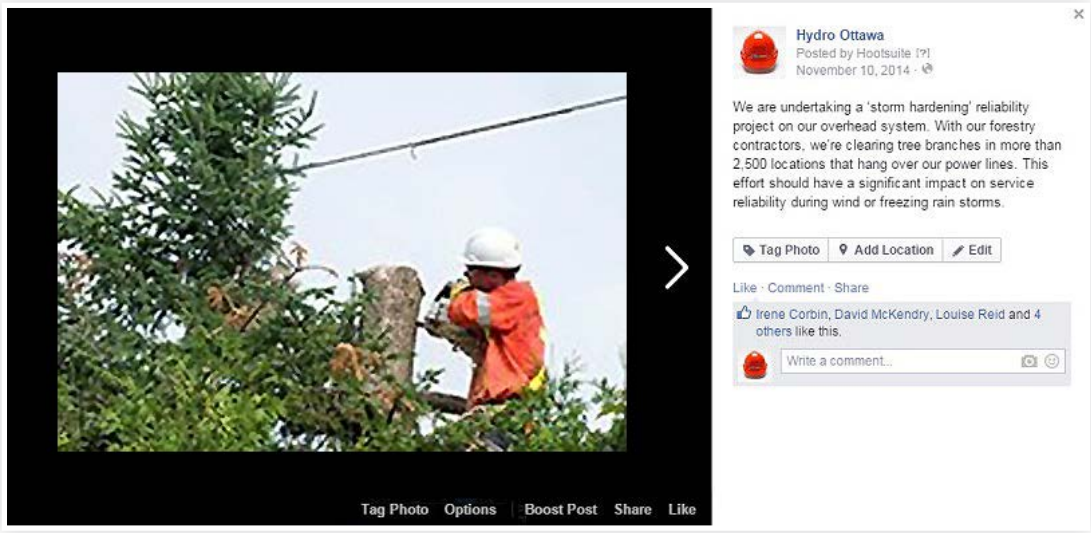


Significant distribution system investments: $125.6 million to address reliability, aging infrastructure and growth

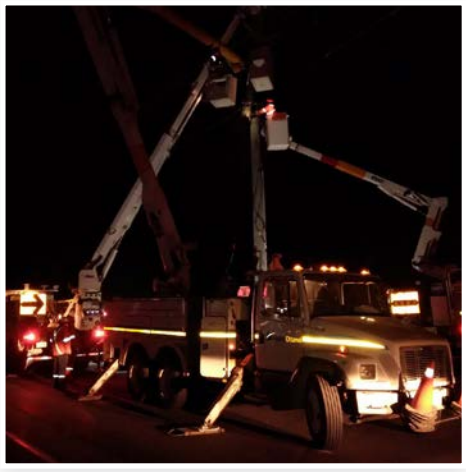
Our overall investment in asset management projects in 2014 was upward of $125.6 million, with a particular focus on areas with chronic reliability issues, new station capacity, plant relocation, system expansion, and commercial infill.

Significant milestones in 2014 included the expansion of the Limebank transformer station to supply the growing communities of Riverside South and Barrhaven and improve their reliability, the addition of a second transmission connection to Marchwood station to provide a higher level of reliability to the North Kanata area, and extensive work to replace aging infrastructure including poles, underground cables, transformers and switchgear, and line extensions throughout our service territory.

Also in 2014, we enhanced our regular year-round tree trimming program that helps reduce contact between trees and overhead power lines. We took 'storm-hardening' measures to ensure that our equipment can withstand extreme weather events such as high winds and heavy snowfall and ice. We identified more than 2,600 spans of overhead power lines where overhanging branches require trimming and completed work to ensure adequate clearance from electrical lines. The investments made are expected to yield significant long-term reliability and productivity benefits.



On September 5, 2014, Hydro Ottawa's distribution system was significantly damaged by high winds, fallen trees and lightning. At its peak, the storm knocked out power to 17,000 customers. Within hours, electrical service was restored to more than half of those affected. Hydro Ottawa initiated emergency response procedures immediately and crews were deployed across the city on a priority basis. Our crews continued to work around the clock to restore power to all affected.



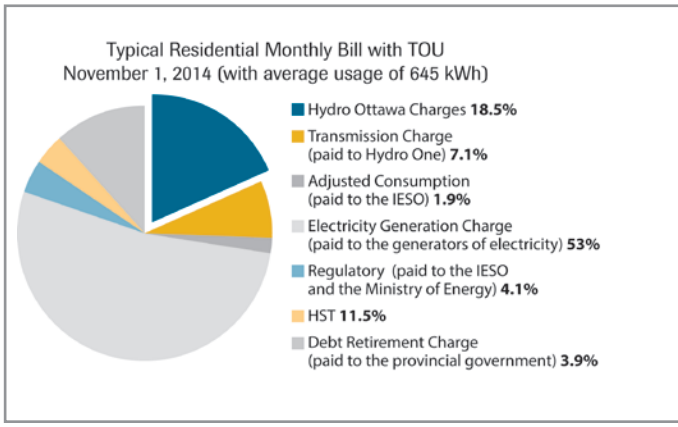
Distribution rates remained stable

Hydro Ottawa's electricity distribution rates are set through open public hearings by the Ontario Energy Board (OEB), Ontario's electricity and natural gas regulator, which regulates the sector and receives policy direction from the Government of Ontario. The OEB approves rates for the distribution of electricity by utilities such as Hydro Ottawa with the goal of protecting the interests of consumers with respect to prices while ensuring that the electrical service provided by utilities is adequate, safe and reliable.

In 2014, Hydro Ottawa's distribution rates made up 20 percent of the customer's total electricity bill. The remaining 80 percent consists of pass-through charges that Hydro Ottawa collects for others, with no markup, including the cost of the electricity commodity.

Hydro Ottawa's distribution rates ensure there are sufficient revenues to maintain a reliable electricity distribution system and provide high quality service.

While the overall customer bill increased in 2014, the approved distribution rate increase for the Hydro Ottawa portion was 1.4 percent effective January 1, 2014.



Organizational Effectiveness

Strategic Objective: We will achieve performance excellence by cultivating a culture of innovation and continuous improvement.

Achieving our goals for customer and shareholder value requires a high performance workforce, and efficient and effective operations. At Hydro Ottawa, we strive for performance excellence in every area of our operations.

Maintaining a healthy and safe work environment remained a top priority

Maintaining a healthy and safe work environment is a critical commitment to our employees. In 2014, Hydro Ottawa provided an average of more than 24 hours of safe work practices training per employee, focusing on higher risk trade employees, who received an average of 46 hours per employee.

Employees worked a total of **1.25 million hours** in 2014 – only 128 hours were lost to workplace injury

Several Hydro Ottawa programs and initiatives were highlighted by the Canadian Electricity Association in their 2014 report *Achieving Excellence in Health and Safety*.

- Our Safe Supervisor Program
- Our National Day of Mourning all-employee ceremony
- Our 2013 North American Occupational Safety and Health (NAOSH) Week events
- Our participation in the GridEx II, a Grid Security Exercise that involved more than 230 utilities and government agencies across North America in order to assess our capability to respond to both physical and cyber security incidents

And our integrated Occupational Health, Safety and Environment management system continued to be certified to the internationally-recognized standards of OHSAS 18001 and ISO 14001.

We kept our focus on ensuring a prepared and sustainable workforce

In light of shifting demographic trends, anticipated retirements and changing skill requirements, we continued to plan and prepare both for continuity of skilled trades and technical capacity, and management succession to ensure a prepared and sustainable workforce over the next five to ten years.

- We forecast our trades and technical requirements to 2024
- We continued to position our workforce for success and advancement through our development and performance management programs

- We launched a Diversity Plan and implemented a number of initiatives focusing on the designated diversity groups; we released our multi-year accessibility plan, supported mental health, and provided cultural competency training for people leaders
- Our five Apprenticeship Programs (Cable Jointer, Meter Technician, Powerline Maintainer, Station Electrician and System Operator) continued to grow — nine new apprentices were hired in 2014, bringing the total to 37 apprentices, representing 22 percent of our trades workforce – and nine apprentices received journeyperson status
- We designated our Algonquin College Powerline Technician Diploma Program partnership as the primary pool for co-op and apprentice candidates; graduated 40 students in 2014 and hired six from the second program cohort in May 2014
- Our Summer and Co-op Student Programs continued to be a vital part of our talent supply strategies; we hired 45 summer and 19 co-op students for a total of 64 — growing our workforce by almost 10 percent in order to provide opportunities to young workers
- Our Engineering Intern Program continued to create a talent pool with five interns receiving their P.Eng. designation for a total of 14 to date
- Our Retiree and Older Worker Engagement Strategy programs continued to be key to engaging workers and managing knowledge transfer

obaa WINNER!

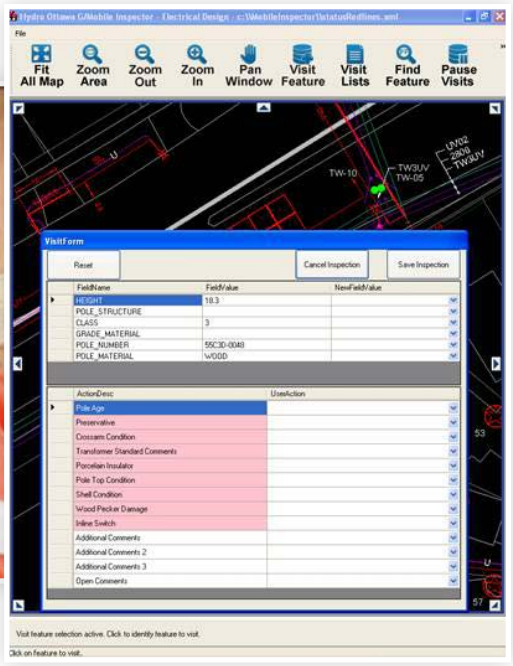
CANADIAN HR Awards 2014 WINNER 2014

Our innovative apprenticeship program and partnership with Algonquin College was recognized with both an Ontario Business Achievement Award and a Canadian HR Award

And we continued to look for ways to improve our operations

As part of our commitment to efficient and effective operations, we maintained our focus on productivity and leveraging technology to enhance service.

We made a number of improvements in 2014 including implementing a technology system to streamline the capital planning process and enhance distribution system investment decisions, and redistributing and improving the scheduling and planning of work to increase the productivity of our workforce and reduce operational overtime hours. We also equipped our mobile field workers with technology to allow them to capture outage information in the field and make it available centrally to improve restoration times. Using mobile resources minimizes customer impact, reduces restore times and keeps repair costs under control. These improvements were direct contributors to the success of our capital and maintenance programs last year.



We also advanced our Facilities Rationalization Plan. The plan involves the sale of three of our existing facilities that are nearing the end of useful life and require major capital investments in the next several years, and the construction of two combined facilities in the east and south ends of the city on two properties that were acquired in 2013 – one near Hunt Club Road and Highway 417 and the other near Fallowfield Road and Highway 416. In 2014, work progressed on the procurement process for the design and build phase, and options for the disposal of existing facilities were explored. When fully implemented, the plan is expected to deliver savings of $3 million annually through a combination of cost reductions and productivity improvements. It will also enhance service through more strategically located and better-equipped facilities, and help to reduce the environmental impact of our operations.

Corporate Citizenship

Strategic Objective: We will contribute to the well-being of the community by acting at all times as a responsible and engaged corporate citizen.

At Hydro Ottawa, we seek to contribute to positive outcomes in our community and beyond.

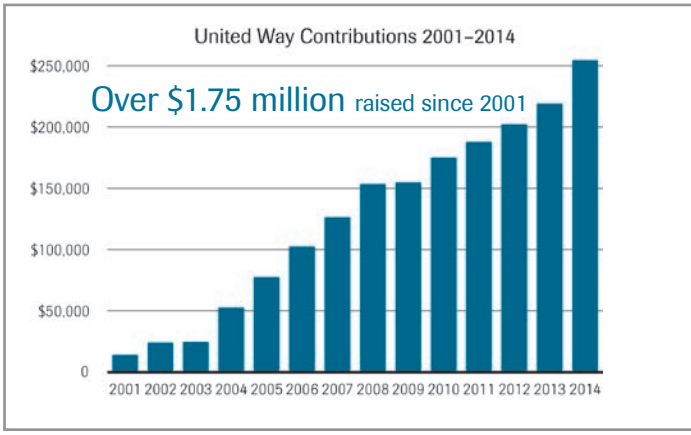
We continued to be active in our community

As a community company that delivers essential services to Ottawa residents, contributing to the well-being of our community has always been a part of Hydro Ottawa's core mandate. In 2014, we continued to be active in our community. We renewed our partnership with Christie Lake Kids (CLK) and sponsored the Hydro Ottawa Sustainable Youth Leadership Centre, which provides a unique opportunity for disadvantaged youths to learn experientially about alternative energy, while building leadership skills. We also sponsored the CLK "Skills through Activity and Recreation" (STAR) Hockey and Skating Program and established the Hydro Ottawa STAR Cup.

Our United Way fundraising efforts raised a record $254,427 in 2014, bringing our 14-year total to more than $1.75 million. As a result of last year's efforts, we were able to provide nearly $170,000 in financial assistance through our Brighter Tomorrows Fund (our United Way corporate matching dollars) to front-line agencies that serve people who are homeless or at risk of being homeless to complete small capital projects that will improve their energy efficiency.

$170,000 in financial assistance to front-line agencies that serve people who are homeless or at risk of being homeless

$254,427 raised for United Way Ottawa from employee donations and corporate matching



We educated 17,676 elementary school students about electricity safety and conservation and were recognized with the Electrical Safety Authority, Ontario Consumer / Home Electrical Safety Award for our program

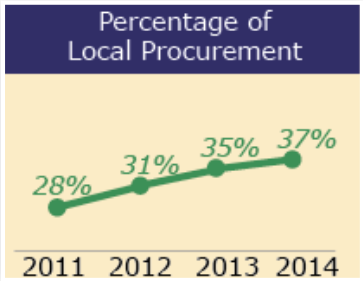
More than 1,600 students in 71 classes from 42 schools registered for our Bright Ideas Contest. Knoxdale Public School and Katimavik Elementary School both received $1,000 to put toward classroom resources

1,700 visitors toured Hydro Ottawa's historic Generation Station No. 2 at Chaudière Falls as part of Doors Open Ottawa on June 5, 2014; we received a Silver Leaf Award of Mention from the International Association of Business Communicators for our event

More than 1,000 children with disabilities enjoyed exclusive access to the Capital Fair, thanks to Hydro Ottawa employee volunteers

We managed our own impacts on the environment

2014 CANADA'S GREENEST EMPLOYERS



Given the inextricable link between energy and the environment, Hydro Ottawa's approach to corporate citizenship includes a strong focus on environmental sustainability. In 2014, we continued to practice what we preach by carefully managing our own impacts on the environment. We added two flex-fuel vehicles to our fleet, maintained a high rate of non-hazardous waste diversion at over 90 percent, introduced technology for remote disconnects / reconnects as opposed to dispatching workers and vehicles, and continued to green our supply chain and procurement processes by purchasing 37 percent of our goods and services from local suppliers. We received the Canadian Electricity Association Environmental Commitment Award. And for the fourth year in a row, Hydro Ottawa was recognized as one of Canada's Greenest Employers for incorporating environmental values into our corporate culture.

Over 90% non-hazardous waste diverted from landfill

We continued to 'walk the talk' through good governance

At Hydro Ottawa, we believe that good governance is the glue that holds together responsible business practices. By making governance a core focus over the past several years, we have established leading practices for a company of our size and mandate. For that reason, in 2014 we engaged third party expertise on governance and undertook a review to ensure more efficient and cost effective governance structures and practices. Reforms were brought forward and approved by the Shareholder, including term limits for Board directors. We also trained all employees and board members on our refreshed Code of Business Conduct that provides greater clarity and guidance to employees and board members in making the right decisions. In addition, we produced our inaugural Corporate Social Responsibility Report to demonstrate our commitment and leadership in this area and share our progress with our stakeholders.

And our performance was recognized once again

For the sixth consecutive year

Sustainability Leader of the Year

New Jersey Governor Chris Christie signed a proclamation declaring December 5, 2014 as “Canadian Utility Appreciation Day” and thanked Canadian electrical and natural gas utilities for their assistance in Super-storm Sandy recovery efforts in 2012

Management's Discussion and Analysis

The Management's Discussion and Analysis ['MD&A'] is intended to provide a narrative review of Hydro Ottawa Holding Inc.'s operational performance and financial position, and should be read in conjunction with the audited consolidated financial statements and accompanying notes for the year ended December 31, 2014. The consolidated financial statements are prepared in accordance with pre-changeover Canadian generally accepted accounting principles ['pre-changeover Canadian GAAP'], including accounting principles prescribed by the Ontario Energy Board ['OEB'] in the Accounting Procedures Handbook, and are expressed in thousands of Canadian dollars.

The MD&A contains forward-looking statements, including, but not limited to, statements as to future operating results and plans. These statements reflect management's expectations as of the date of release. The impacts of risks and uncertainties may cause actual results, performance or achievements to differ materially from those projected here.

Business of Hydro Ottawa Holding Inc.

Hydro Ottawa Holding Inc. ['Hydro Ottawa' or 'the Corporation'] was created as a result of the *Electricity Act, 1998* ['Electricity Act'], which required all hydro utilities to operate as business corporations. It was incorporated on October 3, 2000 under the *Business Corporations Act (Ontario)* as a for-profit holding company that continues to be wholly owned by the City of Ottawa ['the Shareholder'] and is governed by an independent Board of Directors appointed by its Shareholder.

The core businesses of the Corporation are electricity distribution, renewable energy generation and related services. Hydro Ottawa owns and operates two subsidiary companies, as described below:

Hydro Ottawa Limited: The core and by far the largest business of the Corporation is the distribution of electricity, which accounts for approximately 88 percent of the Corporation's capital assets and 89 percent of revenues. Hydro Ottawa Limited is a regulated electricity local distribution company ['LDC'] that owns and operates distribution infrastructure in the City of Ottawa and the Village of Casselman. Hydro Ottawa Limited is the largest LDC in eastern Ontario and the third largest municipally owned LDC in the province of Ontario. Hydro Ottawa Limited delivers electricity reliably and safely to approximately 320,000 residential and commercial customers across a service area of approximately 1,100 square kilometres. As a condition of its distribution licence, Hydro Ottawa Limited is also required to meet conservation and demand management ['CDM'] targets established by the OEB. Hydro Ottawa Limited receives power from the provincial electricity grid and embedded generators and distributes it across a network comprising 85 distribution stations, 169 station class transformers, 2,800 kilometres of underground cable, 2,700 kilometres of overhead lines, 35,700 distribution transformers and approximately 48,000 hydro poles. Hydro Ottawa Limited added 5,000 net new customers to its distribution system in 2014, an increase of 1.6 percent.

Energy Ottawa Inc. (Energy Ottawa): A generator of renewable energy and provider of commercial energy management services, Energy Ottawa is the largest municipally owned producer of green power in Ontario. It owns and operates six run-of-the-river hydroelectric generation plants at Chaudière Falls in the City of Ottawa's core and holds interests in two landfill gas-to-energy joint ventures that convert millions of tonnes of previously flared-off methane gas into renewable energy at the Trail Road landfill site in Ottawa and the Laflèche landfill site in Moose Creek, Ontario. In total, this represents a generation capacity of more than 48 megawatts annually, which is enough to power 40,000 homes. Energy Ottawa has also embarked on a multi-year project to expand its Ontario generation facilities at Chaudière Falls with the expanded generation production capacity expected in the fourth quarter of 2017. This expansion will increase Energy Ottawa's total capacity from 48 megawatts to 68 megawatts.

Vision and Strategy

OUR VISION

Hydro Ottawa's vision is to be a leading and trusted integrated utility services Corporation. This vision is built upon the objectives that were set out for the Corporation at its inception – to increase the value of the Corporation for its Shareholder, to deliver efficient and effective service to our customers, and to grow competitive businesses that maximize the value of our existing assets and core competencies.

The goal throughout Hydro Ottawa's *2012–2016 Strategic Direction* is to move the Corporation from 'good to great', leveraging our position as a leading and trusted service provider to become one of Canada's most successful integrated utilities.

LEADING

For Hydro Ottawa, leading means consistently being among the top performers in the business in every critical area of our operations, and being regarded as a credible and trusted voice in our industry, helping to shape policy, regulatory and operational responses to the critical issues of the day.

As our industry evolves in response to customer needs and technological and policy change, our goal is to ensure Hydro Ottawa continues to be a leader in this shifting strategic context, becoming one of the most successful utility companies in Canada.

TRUSTED

Trust is fundamental to Hydro Ottawa's success; a continuing belief among our stakeholders that we will deliver on our mission, reliably, in a transparent and accountable fashion.

We are a Corporation with very deep roots in our community, established through more than 100 years of providing an essential service to homes and businesses, and we continue to be recognized as a service leader through numerous awards for our Human Resources innovation, leading safety and customer programs, corporate social responsibility, and business excellence.

In the years to come, we will continue to demonstrate that we have the strength and ability to deliver on our mandate, coupled with a commitment to transparency, accountability, and the well-being of our community.

INTEGRATED

While yesterday's most successful utilities were vertically integrated – providing generation, transmission and distribution services – a new model of integrated utility is emerging based on a well-connected value chain in 'close to the customer' utility services. These horizontally integrated utilities are leveraging the synergies between utility functions to deliver efficiencies to customers, and value to shareholders.

The distribution of utility commodities is similar, whether the commodity is electricity, water or heat. The skill sets employed to develop renewable energy facilities and install electrical infrastructure can be applied to other energy systems, such as district energy and distributed generation.

Hydro Ottawa's strategic vision involves realizing synergies and economies of scale in 'close to the customer' utility services, to create additional value for the Corporation's Shareholder, savings and enhanced service to customers.

OUR STRATEGY

The essence of Hydro Ottawa's strategy is to put the customer at the centre of everything we do. Understanding and responding to the customer's needs and expectations for service quality, cleaner energy, and greater control over the management of energy costs will be key to Hydro Ottawa's continued success in an evolving landscape. The customer value we provide up to and beyond the meter will drive all critical areas of performance - our financial strength and business growth, our operational efficiency and effectiveness, and our contributions to the well-being of our community.

To enhance our ability to respond to customer needs and expectations, and ensure long-term financial sustainability, Hydro Ottawa will also maintain a focus on strategic business growth within our core areas of strength. Our growth agenda involves three basic components:

- achieving economies of scale by expanding our electricity distribution business beyond its current service territory, and leveraging our core systems to support other utility services;
- increasing the supply of clean energy for customers and earnings for our Shareholder by expanding our renewable generation; and
- bringing innovative solutions to energy-conscious consumers and businesses by growing our energy management expertise.

Our strategy is structured around four critical areas of performance. These have driven our success to date and will continue to guide our activities throughout the current strategic plan. Hydro Ottawa refers to these as our four Key Areas of Focus, with Customer Value taking on central importance:

- Customer Value: We will deliver value across the entire customer experience;
- Financial Strength: We will create sustainable growth in our business and our earnings;
- Organizational Effectiveness: We will achieve performance excellence; and
- Corporate Citizenship: We will contribute to the well-being of the community.

Electricity Distribution — Industry Overview

THE ROLE OF THE LOCAL DISTRIBUTION COMPANY

Ontario's LDCs take power from the high-voltage transmission grid, reduce the electricity voltage to a lower level [50,000 volts and under], and provide this electricity to customers, homes, businesses, institutions and industry. They also provide energy conservation services to their customers, as a condition of their distribution licenses issued by their regulator, the OEB.

The functions carried out by Ontario's LDCs include the following:

- Plan: Review performance and trending, project consumer demand growth, develop capital and maintenance plans;
- Design: Apply standards and rigor to projects and retrofits and execute plans;
- Build: Bring the conceptual design to construction;
- Operate: 24/7 operations;
- Maintain: Manage physical assets;
- Restore: Outage management, customer communications;
- Meter: Measure the customer's consumption;
- Bill: Obtain all the usage information and send the bill to the customer;
- Settle: Act as the billing agent for other organizations in Ontario's electricity system;
- Collect: Manage payment collection;
- Conserve: Promote conservation and demand management programs; and
- Customer Care: Manage the relationship with customers.

REGULATORY ENVIRONMENT

The legal and policy framework for the Corporation's businesses is set mainly by the Government of Ontario, which passes legislation and regulations that govern the energy sector in the province. The Ministry of Energy works to develop the electricity generation, transmission and other energy related facilities in Ontario. The Ministry of Energy also has legislative responsibility for several agencies, including the Independent Electricity System Operator ['IESO'], the OEB and the Ontario Power Authority ['OPA']. The government restructured Ontario's electricity industry in 1998, which allowed utilities to provide service, build, and maintain infrastructure to meet or exceed regulated standards, while earning a regulated return on invested capital.

In April 2012, the Minister of Energy established the *Ontario Distribution Sector Review Panel* [the '2012 Panel'] to provide expert advice to the government on how to improve efficiencies in the sector, with the aim of reducing the financial cost of electricity distribution for electricity consumers. The 2012 Panel's report, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, was published in December 2012. Based on a thorough review of the sector, the Panel proposed a new model for electricity distribution in Ontario aimed at creating robust, efficient and well-resourced utilities that will reduce costs to the consumer and support continued economic growth, largely through the consolidation of LDCs into larger regional utilities.

In April 2014, the Minister of Finance announced a council to provide advice on government assets, reporting directly to the Premier. The Premier's Advisory Council on Government Assets released an initial report on November 13, 2014. The initial report supports the core conclusions of the 2012 Panel that Ontario needs a more consolidated and efficient electrical distribution system, and that barriers which impede consolidation should be reviewed.

Hydro Ottawa is well positioned to respond to opportunities involving regional consolidation where there is a clear benefit to our customers and our Shareholder.

Effective January 1, 2015, the Ministry of Energy redefined the roles of the IESO and the OPA by combining the two agencies into one agency under the IESO.

REGULATORY FRAMEWORK

Hydro Ottawa and its subsidiaries operate within the framework of the Electricity Act and the *Ontario Energy Board Act, 1998* ['OEB Act'].

The Electricity Act establishes the structure of the electricity industry and the roles and responsibilities of parties such as the IESO, Electrical Safety Authority, OPA and the Smart Meter Entity. The Electricity Act further establishes rights and obligations for distributors. For instance, distributors are obligated to connect any building that lies along their distribution systems upon request and access to its system must be non-discriminatory.

The OEB Act establishes the authority and power to approve and fix all rates for the transmission and distribution of electricity in the province. In addition to setting or approving all rates charged by Hydro Ottawa Limited, the OEB establishes standards of service and conduct that must be followed as a condition of being licensed to distribute electricity.

Hydro Ottawa Limited, as an electricity distributor, is both licensed and regulated by the OEB. Hydro Ottawa Holding Inc. and Energy Ottawa also have restrictions on business activities because they are affiliates to a distributor that is owned indirectly by a municipal corporation. Energy Ottawa and its affiliates are also licensed by the OEB as an electricity retailer and generator.

The permitted business activities of Hydro Ottawa Limited were expanded in 2009 as a result of the *Green Energy and Green Economy Act, 2009* ['Green Energy Act'] to include the ownership and operation of generation and energy storage facilities under established criteria. The Green Energy Act requires all distributors to file plans with the OEB on facilitating renewable energy generation and implementing a smart grid. It also amended the mandate of the OEB, expanding its objectives to include the promotion of CDM, facilitating the implementation of a smart grid and promoting the use and generation of electricity from renewable energy sources. On November 12, 2010, Hydro Ottawa Limited's distribution licence was revised to reflect its additional mandate to achieve CDM targets. The Corporation filed its Green Energy Act plan with its 2012 Cost-of-Service application. The Green Energy Act establishes mandatory timelines and information requirements for each step of a process established for the connection of generation facilities that sell electricity through the distribution grid. In December 2014, a new province-wide program for CDM was announced by the Ministry of Energy, which has resulted in additional amendments to Hydro Ottawa Limited's Distribution Licence regarding CDM activities and targets effective December 18, 2014.

The Ontario electricity commodity market is open to competition at both the wholesale and retail levels. Since 1999, electricity distributors have been purchasing their electricity from the wholesale market overseen by the IESO and recovering costs of electricity in accordance with procedures mandated by the OEB. At the wholesale level, generators can bid into the electricity market overseen by the IESO or enter into a contract with the OPA. At the retail level, consumers have the choice of purchasing the electricity commodity through a contract with a licensed electricity retailer or through a licensed distributor, such as Hydro Ottawa Limited, as part of a standard supply service ['SSS']. Under a SSS, the commodity is provided to customers on a pass-through basis such that commodity revenues match the cost. Residential and small commercial customers receive the SSS through a regulated price plan ['tiered'] or Time-of-Use ['TOU'], under which the OEB sets the commodity rates for the province twice per year, in May and November, based on a forecast of the commodity costs.

Differences between the forecast and actual costs are tracked by the OEB in a variance account until the balance is cleared through future regulated commodity rates. Other customers pay for the commodity based on the provincial spot market price or through the terms of a retail contract.

Regardless of whether customers have signed a contract with a retailer, or are supplied through a SSS, Hydro Ottawa Limited continues to be responsible for the delivery of the electricity through its distribution system to all customers within the licensed service area.

DETERMINING DISTRIBUTION RATES

Ontario's electricity distribution companies, such as Hydro Ottawa Limited, recover their costs from customers through electricity distribution rates, including the costs to:

- design, build and maintain overhead and underground distribution lines, poles, stations and local transformers;
- operate local distribution systems, including smart meters; and
- provide customer service and emergency response.

Before LDCs can make any changes to their rates, they are required to seek approval from the OEB through a rate application. The OEB follows a multi-year process to set electricity distribution rates. The process is designed to encourage distribution companies to maximize their efficiency while generating the revenue required to reliably deliver electricity to consumers.

In 2011, the OEB initiated a review of the 3rd Generation Incentive Regulation Mechanism ['IRM'] regulatory model for electricity distributors in Ontario, as part of a broader review of the regulatory framework for electricity in the province. Over the past five years of operating under the 3rd Generation IRM, electricity distributors have raised a number of concerns with the model, including a concern that it did not provide adequate recovery for capital expenditures in the intervening years between rebasing. On October 18, 2012, the OEB announced a new policy framework for regulation of the electricity industry in Ontario ['Renewed

Regulatory Framework for Electricity Distributors: A Performance-Based Approach']. Recognizing that the capital investment needs of LDCs vary over time, the new framework identified three rate-setting models from which LDCs will be able to choose to set their rates:

- 4th Generation Incentive Rate-setting [suitable for most distributors];
- Custom Incentive Rate-setting [suitable for those distributors with large or highly variable capital requirements]; and
- Annual Incentive Rate-setting Index [suitable for distributors with limited incremental capital requirements].

The OEB believes these models will provide choices suitable for distributors with varying capital requirements, addressing the issues raised by electricity distributors regarding recovery of capital expenditures, while allowing greater focus by the electricity distributors on customer value and service. During 2013, the details of each of the regulatory models was developed with input from working groups comprised of electricity distributor staff, ratepayer groups and OEB staff. In November 2013, the OEB issued its final report on the details of the 4th Generation Incentive Rate-setting and the Annual Incentive Rate-setting Index models. Hydro Ottawa was actively engaged in the policy-making process through working groups and in other ways, which influenced the final design of these models. Electricity distributors can file applications under one of the three new models for 2015 rates.

Hydro Ottawa's rates for 2014 and 2015 were established by using the 4th Generation Incentive rate-setting model. Under this method, Hydro Ottawa's rates were adjusted by 1.4 and 1.3 percent, commencing on January 1, 2014 and January 1, 2015, respectively. These inflationary adjustments were determined by the OEB as appropriate for electricity distributors.

Hydro Ottawa is planning to file a Custom Incentive Rate-setting application with the OEB in early 2015 for rates for the period January 1, 2016 through December 31, 2020. Hydro Ottawa's plan to file a Custom Incentive Rate-setting application is based upon Hydro Ottawa's need for large capital requirements during that period. The OEB will hold an open and transparent hearing process throughout 2015 and Hydro Ottawa expects to receive the OEB's decision on this application in the 4th quarter of 2015.

Costs and rates vary from distributor to distributor depending on factors such as the age and condition of assets, geographic terrain and distance, and population density and growth. The proportion of residential to commercial and industrial consumers can also contribute to cost differences between distribution companies. Electricity bills include charges for the commodity, wholesale market services, transmission services, distribution services, debt retirement, and harmonized sales tax. Revenues from all of these charges, except distribution services, are collected from customers on a pass-through basis. Any differences between costs and revenues collected for these pass-through charges are tracked as a regulatory asset or liability, to be cleared through rates in a subsequent period. Distribution services revenue, which represents only about 20 percent of the bill, is the only amount retained by the LDC. The OEB-approved distribution rates include a fixed charge and a variable charge based on electricity consumption or peak demand. Each year the OEB compares the operating costs per customer of all Ontario distributors. In August 2014, the OEB issued the 2013 Yearbook of Electricity Distributors, Hydro Ottawa ranked in the top quartile of distributors in terms of lowest costs per customer [15th out of 73 electricity distributors].

Selected Consolidated Financial Results

The selected consolidated financial results of the Corporation presented below should be viewed in conjunction with the audited consolidated financial statements for the year ended December 31, 2014.

CONSOLIDATED STATEMENT OF INCOME (SUMMARY)

(in thousands of Canadian dollars)	2014	2013	Change
Revenue			
Power recovery	799,272	768,079	31,193
Distribution sales and other revenue	213,077	208,288	4,789
	1,012,349	976,367	35,982
Expenses			
Purchased power	795,703	765,151	30,552
Operating costs	123,258	114,291	8,967
	918,961	879,442	39,519
EBITDA	93,388	96,925	(3,537)
Depreciation and amortization	39,629	40,322	(693)
Impairment charges	4,023	–	4,023
Financing costs	17,401	14,645	2,756
Payments in lieu of corporate income taxes	1,812	9,410	(7,598)
	62,865	64,377	(1,512)
Non-controlling interest	(205)	(406)	201
Net income and comprehensive income	30,318	32,142	(1,824)

Net income decreased by approximately $1.8 million [6 percent] in 2014. The decrease is largely attributable to $4.0 million of impairment charges recognized as a result of Hydro Ottawa's decision to proceed with a significant expansion of generation assets at Chaudière Falls as noted below under impairment charges. Hydro Ottawa also realized increases in operating costs as a result of inflationary and contractual increases such as compensation along with new operational initiatives. Rising operational costs were partially offset by modest increases in distribution and other revenue, along with a reduction in taxes precipitated by the accelerated write-off of the new Customer Care and Billing System ['CC&B'] that was implemented during the year.

REVENUE

Revenue is earned from electricity distribution, sales of generated power, energy management services, the CDM programs and sundry activities. In 2014, Hydro Ottawa's total revenue exceeded $1.0 billion, an increase of $36.0 million [4 percent].

The largest component in Hydro Ottawa's total revenue is the cost of power recovered from the customer through provincially established rates. The cost of power is a flow-through amount, which poses limited risk to Hydro Ottawa's financial performance either positively or negatively. Hydro Ottawa Limited's power recovery increased by $31.2 million [4 percent], mainly due to increases in commodity and global adjustment rates included in purchased power costs.

Revenue, excluding power recovery, increased $4.8 million [2 percent] from 2013. Electricity distribution revenue is reflective of OEB approved distribution rates and the amount of electricity consumed. Revenue from distribution sales increased $4.2 million [3 percent] from 2013 due to customer growth and a modest increase in rates established by means of the 4th Generation Incentive rate-setting index. While Hydro Ottawa once again saw a rise in recoveries of $3.6 million stemming from its CDM programs, revenues from sundry activities decreased by $3.1 million as a result of significant revenue earned from a large recoverable work contract in 2013. Energy Ottawa's electricity generation revenues remained strong and would have surpassed 2013 had it not been for the required shutdown of generating assets for repairs to the Bronson bulkhead. Generation revenues would have been approximately $1.9 million higher if this shutdown had not been required, however Energy Ottawa's commercial energy management services experienced increased activity which more than made up for the generation shortfall.

EXPENSES

Purchased power costs represent the cost of electricity delivered to customers within Hydro Ottawa Limited's distribution service territory. These costs consist of the commodity, wholesale market service charges, transmission charges and the global adjustment levied by the IESO, net of energy generated by Energy Ottawa and supplied to Hydro Ottawa Limited as an embedded generator within Hydro Ottawa Limited's service territory. The cost of purchased power increased by $30.6 million [4 percent], mainly due to increased commodity and global adjustment rates. The global adjustment accounts for differences between the market price and the rates paid to regulated and contracted generators and for CDM programs. When the spot market price of electricity is lower, the global adjustment is higher in order to cover the additional costs of energy contracts and other regulated generation.

Operating costs in the current year of $123.3 million increased by $9.0 million over 2013 due in part to negotiated and inflationary compensation costs, which have increased over the prior year by approximately $2.3 million [3 percent], and a $4.2 million increase in maintenance and other operating and administrative costs. The increase in maintenance expenses is largely due to a storm-hardening project initiated in 2014 across Hydro Ottawa's service territory to ensure adequate tree clearance from overhead power lines as well as costs incurred to repair damages caused by the September 5, 2014 windstorm that left 17,000 customers without power. The CDM programs' costs have also increased over the prior year by $3.9 million offset by corresponding increased revenues.

DEPRECIATION AND AMORTIZATION

Depreciation on Hydro Ottawa's property, plant and equipment increased slightly in 2014 by $1.2 million primarily due to the ongoing investment in the Corporation's electricity distribution infrastructure. Conversely, amortization expense on the Corporation's intangible assets decreased by $1.9 million as Hydro Ottawa's previous billing system became fully amortized at the end of 2013 and was replaced in March 2014 with the upgraded CC&B system.

IMPAIRMENT CHARGES

On February 7, 2014, Energy Ottawa's subsidiary Chaudiere Hydro L.P. was granted a forty year Hydroelectric Standard Offer Program – Municipal Stream Contract ['HESOP Contract'] by the OPA to produce renewable waterpower. With the HESOP Contract and approval of the Board, the Corporation embarked on a multi-year project to expand its Ontario generation facilities at Chaudière Falls increasing its total capacity by 20 megawatts. The anticipated commercial operation date is in the fourth quarter of 2017. Chaudiere Hydro L.P. must permanently decommission the two Ontario generating stations at Chaudière Falls in July of 2015 to allow for the construction of the new hydroelectric generation facility. Consequently, the Corporation has recorded an impairment charge of $4.0 million, of which $2.8 million relates to generating plants and equipment while the remaining $1.2 million pertains to the power purchase agreement with Hydro Québec, as the new facility will operate under the new HESOP Contract instead.

FINANCING COSTS

Financing costs have increased in the current year as a result of the issuance of new senior unsecured debentures in the amount of $150 million, which occurred in May 2013.

PAYMENTS IN LIEU OF CORPORATE TAXES ['PILS']

The Corporation's effective tax rate decreased from 22.4 percent in 2013 to 5.6 percent in 2014. The year-over-year decrease is a result of impacts of permanent and temporary differences between the accounting and tax basis of assets and liabilities. Specifically, Hydro Ottawa Limited's CC&B system, which went live in 2014, is amortized at an accelerated rate for tax purposes and has resulted in a significant reduction in current taxes. As the Corporation is able to recover future PILs through annual distribution rate adjustments as approved by the OEB, it records liabilities and assets for the amounts of future taxes expected to be refunded to (or recovered from) customers in future rates. For additional details regarding PILs see Notes 2(f)(iv) and 21 to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET (SUMMARY)

(in thousands of Canadian dollars)	2014	2013	Change
Current assets	160,571	183,697	(23,126)
Non-current assets	899,722	824,859	74,863
Total assets	1,060,293	1,008,556	51,737
Current liabilities	193,746	162,239	31,507
Non-current liabilities	468,476	462,164	6,312
Total liabilities	662,222	624,403	37,819
Shareholder's equity	398,071	384,153	13,918
Liabilities and shareholder's equity	1,060,293	1,008,556	51,737

ASSETS

Total assets increased by approximately $51.7 million during the year. This increase is largely attributable to property, plant and equipment and intangible assets, which have increased by $75.4 million. This is a result of our continuing investment in electrical distribution and generation infrastructure. Offsetting this increase is a $24.7 million decrease in unbilled revenue stemming from Hydro Ottawa's transition to a monthly billing cycle during the year for its residential and small commercial customers. The move to a monthly billing cycle coincided with Hydro Ottawa's CC&B system upgrade.

LIABILITIES

Total liabilities increased by $37.8 million in 2014. Increases were highlighted by a $22.6 million rise in purchased power payable, a $7.1 million increase in the Corporation's bank indebtedness, and $15.7 million in capital contribution obligations recognized during the year. While the purchased power payable coincides with the increased expense and related global adjustment costs during the year, the capital contribution obligations arose based on a true up of Hydro Ottawa Limited's Connection and Cost Recovery Agreements with Hydro One Networks Inc. As the initial load forecasts under these agreements were higher than the actual and revised load forecasts, Hydro Ottawa is now obligated to make up the $15.7 million shortfall.

STATEMENT OF CASH FLOWS (SUMMARY)

(in thousands of Canadian dollars)	2014	2013	Change
Bank indebtedness, beginning of year	(8,853)	(77,357)	68,504
Cash provided by Operating Activities	108,614	49,430	59,184
Cash used in Investing Activities	(101,145)	(112,184)	11,039
Cash (used in) provided by Financing Activities	(14,571)	131,258	(145,829)
Bank indebtedness, end of year	(15,955)	(8,853)	(7,102)

CASH PROVIDED BY OPERATING ACTIVITIES

Cash generated by operating activities grew by $59.2 million in 2014. The majority of this increase relates to positive fluctuations within working capital, namely a $41.4 million increase in cash as a result of the transition to monthly billing, and a $21.8 million upswing in cash from accounts payable and accrued liabilities as a result of the elevated amount of purchased power payable at year end.

CASH USED IN INVESTING ACTIVITIES

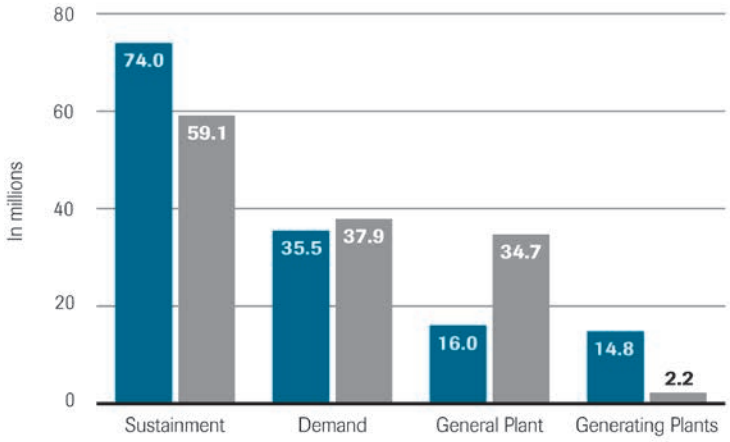
The total 2014 investment in property, plant and equipment and intangible assets, net of contributed capital is approximately $121 million [$101 million – net of non-cash transactions such as capital purchases included in accounts payable and accrued liabilities and proceeds from disposal]. Refer to the capital expenditures section below for additional information.

CASH PROVIDED BY FINANCING ACTIVITIES

Dividends were paid to the Shareholder in 2014 in accordance with the approved dividend policy. The 2014 payment totaled $19.3 million based on 2013 results, and the 2013 payment totaled $18.6 million based on 2012 results. Moreover, the prior year cash flows included a $150 million bond issuance, which occurred in May of 2013.

CAPITAL EXPENDITURES

Investment in the Hydro Ottawa Limited electricity distribution system continues to be robust. Hydro Ottawa invested heavily in its distribution system and aging infrastructure again in 2014. The gross capital expenditures were $140.4 million in 2014, offset by capital contributions; this amounted to $121.2 million, an increase of $9.5 million or 9 percent over the prior year. The following chart shows Hydro Ottawa's capital investments by category for both 2014 and 2013:



Capital investments in 2014 included approximately $74 million on sustainment capital to replace aging infrastructure and to modify the existing distribution system; $36 million on demand projects [offset by contributed capital of $19 million], which includes third-party driven growth projects such as new residential or commercial installations, and municipal improvement projects including the City of Ottawa's Light Rail Transit project; $16 million on general plant including Information Technology infrastructure, fleet, and other sundry items; and $15 million in generating plants, which includes preliminary work for the expansion at Chaudière Falls.

In 2014, 1,057 new poles, 374 overhead transformers, and 209 km of overhead cables were installed. Over 210 demand capital projects were initiated, including the addition of 4,310 new residential and 713 new commercial connections.

General plant was significantly higher in the previous year as it contained the bulk of Hydro Ottawa's new CC&B system costs, while generating plants increased this year as a result of the Bronson bulkhead construction costs and the start of the expansion at Chaudière Falls.

SUBSEQUENT EVENT

Subsequent to year end, on February 2, 2015, the Corporation completed a dual tranche debt offering consisting of $200 million, 2.614%, 10 year and $175 million, 3.639%, 30 year senior unsecured debentures. The proceeds were used to refinance the Corporation's $200 million Series 2005-1 debentures maturing on February 9, 2015 and indebtedness under its credit facility, as well as for general corporate purposes including capital expenditure requirements.

On March 23, 2015, the Corporation, through its subsidiary Energy Ottawa, entered into a share and unit purchase agreement to acquire a variety of generation-related entities. The agreement includes numerous closing conditions which can have a material impact on the total purchase price. Hence, the value of the purchase commitment is not determinable at this time. The closing of this transaction is currently expected to occur in the second quarter of 2015.

LIQUIDITY AND CAPITAL RESOURCES

The Corporation's primary sources of liquidity and capital resources are derived from operating activities, banking facilities, and proceeds from bond issuances as and when required. Liquidity and capital resource requirements are primarily for capital expenditures to maintain the Hydro Ottawa Limited electricity distribution system, cost of power, interest expense and prudential requirements.

On July 21, 2014, the Corporation renewed its credit facility for $336 million. The Corporation may use up to $75 million of the facility for general operating requirements and annual capital expenditures. A $100 million three-year revolving credit line remains available for larger capital expenditures and acquisitions. To ensure appropriate liquidity, an additional $150 million one-year credit line was also placed. Capital expenditure requirements in excess of this, if any, will be funded through future bond issuances.

As at December 31, 2014, the Corporation had drawn $9.3 million in standby letters of credit and $37 million in short-term borrowings against its credit facility. The remaining facility is adequate to support the short-term working capital deficit experienced each month to settle the IESO costs of power invoice in advance of receiving payment from customers.

The Corporation's bonds carry covenants normally associated with this type of debt [see Notes 15 and 16 of the consolidated financial statements for further details]. The Corporation is in compliance with these covenants as at December 31, 2014.

For additional details regarding the Corporation's sources of liquidity and capital resources, see Notes 9, 15 and 19(b) to the consolidated financial statements.

CREDIT RATINGS

Both Standard & Poor's Rating Services Inc. and Dominion Bond Rating Service Inc. reaffirmed Hydro Ottawa's rating at 'A' with a stable trend noting the Corporation's strong competitive position and a recession resistant customer base promoting an excellent business risk profile. Hydro Ottawa's strong credit rating over the past several years is a direct result of its conservative financial policies, strong operational performance and low business risk.

ACCOUNTING ESTIMATES AND POLICIES

SIGNIFICANT ACCOUNTING ESTIMATES

The preparation of consolidated financial statements, in conformity with pre-changeover Canadian GAAP, requires management to make estimates and assumptions that affect the reported amounts of consolidated revenues, expenses, assets, liabilities, and the disclosure of commitments and contingencies as of the date of the consolidated financial statements.

These estimates are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Because they involve varying degrees of judgment and uncertainty, the amounts currently reported in the financial statements could prove to be inaccurate in the future.

The following accounting estimates require management's judgments and assumptions in preparing financial statements and, as such, are considered to be critical. References to the associated note in the consolidated financial statements are provided in brackets:

- Useful lives of property, plant and equipment and intangible assets [Note 2(j) and (k)]
- Unbilled revenue [Note 2(g)(iii)]
- Regulatory assets and liabilities [Note 6]
- Capital contribution obligations [Note 13]
- Employee future benefits [Note 14]
- Payments in lieu of corporate income taxes [Note 21]
- Allowance for doubtful accounts [Note 19(b)(ii)]
- Contingent liabilities [Note 22]

FUTURE CHANGES IN ACCOUNTING POLICIES

On February 13, 2008, the Canadian Accounting Standards Board ['AcSB'] confirmed that publicly accountable enterprises ['PAEs'] would be required to transition to International Financial Reporting Standards ['IFRS'] effective January 1, 2011. While the Corporation is not a PAE, it is a Government Business Enterprise given its status as a municipally owned utility, and such enterprises are required to follow the same basis of accounting as PAEs.

On the original transition date, IFRS did not contain a standard governing rate-regulated activities ['RRA']. Due to the significance of this issue in Canada, the AcSB postponed the original IFRS transition date to January 1, 2015 for qualifying entities with RRA pending the completion of an interim standard by the International Accounting Standards Board ['IASB']. Until January 1, 2015, qualifying entities are permitted to continue reporting under pre-changeover Canadian GAAP.

On January 30, 2014, the IASB issued interim standard IFRS 14 - Regulatory Deferred Accounts ['IFRS 14'] which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices. This standard becomes effective January 1, 2016 with early adoption permitted. The Corporation adopted IFRS and early adopted IFRS 14 on January 1, 2015. The Corporation has assessed the implications of adopting IFRS and is currently reviewing its impact on the financial reporting.

CRITICAL NON-CAPITAL RESOURCES AND INTERNAL PROCESSES

CRITICAL NON-CAPITAL RESOURCES

The Corporation employs over 650 people with Hydro Ottawa Limited accounting for over 90 percent of this workforce.

Over 40 percent of Hydro Ottawa's workforce become eligible to retire by 2023, of which, almost 60 percent are skilled workers in trades or technical professions; the other 40 percent are management, administrative, professional, and clerical employees. This reflects a broader trend of workforce demographics seen by utilities in Ontario and across Canada.

In planning for these retirements, Hydro Ottawa has put in place a comprehensive and integrated talent management strategy to ensure a sustainable and prepared workforce. This includes:

- Extensive in-house apprenticeship programs, and an engineering intern training and development program, to ensure the availability of qualified journeypersons and professional engineers;
- A succession planning and management program and training and development program to ensure that there are qualified employees in the talent pipeline for key positions;
- A proactive approach to knowledge management and knowledge transfer for key positions, including an older worker and retiree engagement strategy so that work is seamlessly transitioned from our veteran workforce to the next generations;
- A Diversity Plan to create and support a talented workforce that is reflective of the diversity in the communities we serve; and
- Partnerships with industry and educational institutions to support the implementation of the talent management strategy. These include, most notably, collaborations with Algonquin College to deliver the College's new Powerline Technician diploma program, and with Carleton University's Sustainable and Renewable Energy Engineering Department for the establishment of a smart grid laboratory to foster innovative research on electrical power systems and promote the training of engineers in the smart grid environment.

The Corporation provides a defined benefit pension plan for the majority of its employees, through the Ontario Municipal Employees Retirement System ['OMERS']. As a result of the acquisition of assets from Domtar Inc. on November 20, 2012, the Corporation established a defined benefit pension plan for approximately 20 employees who were previously employed by Domtar Inc. A Retirement Committee undertakes the management, operation and administration of this pension plan; this Committee through the Governance and Management Resources Committee reports to the Hydro Ottawa Holding Inc. Board of Directors.

INTERNAL PROCESSES

Various technologies and processes have been introduced to enhance sustainability and better manage electrical distribution assets and improve customer service, including increasing the automation and reliability of the network through faster restoration times. Hydro Ottawa believes a commitment to sustainability is important not only because it benefits the environment, but also because it improves the Corporation's business.

In 2014, the Corporation continued to focus on leveraging customer access to their account information through customer self-serve options. These options result in improved customer satisfaction, fewer complaints and improved efficiencies. As of December 31, 2014, over 122,000 customers [38 percent of all customers] had subscribed to MyHydroLink, a web-based customer portal that provides a number of self-service options. Almost 86,000 customers have also opted to receive their Hydro Ottawa bill electronically, and over 66,000 customers have subscribed to an automated payment process that is more convenient for them and more efficient for the utility. Customer use of Hydro Ottawa's mobile web offering continued to increase in popularity in 2014. This mobile service features many customer account information options along with access to Hydro Ottawa's award winning Outage Communications system. Hydro Ottawa Mobile is available to customers with a smart phone such as an iPhone, Android device or Blackberry.

In 2014, Hydro Ottawa continued to deploy a Remote Disconnect/Reconnect feature that allows electrical service to be interrupted and restored to a customer's premises remotely by Hydro Ottawa staff. This allows Hydro Ottawa to restore service to customers more quickly and reduce the number of truck-rolls required to respond to non-payment situations. Over 11,000 meters are now equipped with this feature.

A key and very notable upgrade to Hydro Ottawa's customer information and billing system was completed and deployed on March 6, 2014. In conjunction with this upgrade, Hydro Ottawa converted all residential and small commercial customers to a monthly billing cycle, in place of the bi-monthly cycle. Coincidentally, on February 5, 2015, the OEB issued proposed amendments to the Distribution System Code, which would require every electricity distributor in Ontario to bill its residential and small commercial customers on a monthly basis no later than January 1, 2017. Hydro Ottawa is therefore already fully compliant with the new proposed rules on monthly billing.

Hydro Ottawa Limited also continues to maintain certification to several international standards, including ISO 9001 Quality Management System, ISO 14001 Environmental Management System and OHSAS 18001 Occupational Health and Safety Management System. The certifications for the latter two management systems have been extended to Energy Ottawa generation facilities and business operations in 2014. Internal and external third-party audits are conducted annually to confirm and maintain certification and to attain re-registration as required by the standards.

The Corporation continues to place a significant emphasis on cost containment and productivity improvements in order to enhance financial strength and operational performance. The OEB sets productivity improvement targets for electricity distributors as part of its Incentive Regulation Mechanism, and the Corporation pursues corporate-wide efficiencies in addition to those targets. These initiatives include the deployment of an Asset Optimization Tool in 2014 and a Mobile Workforce Management Tool for 2015. Also in 2014, Hydro Ottawa established a productivity team to develop corporate productivity scorecard measures and we have begun monitoring and reporting progress quarterly.

Lastly, as part of a broader corporate strategy, Hydro Ottawa is focused on the need to yield productivity benefits through consolidation of work, rationalization of headcount for redeployment to trades hiring, and ongoing evaluation of possibilities to outsource work that is not considered to be a core or valued-added aspect of service delivery.

RISKS AND UNCERTAINTIES

The ability to manage and mitigate risk, to maintain flexibility, and to respond effectively to changes in our business environment is critical to the Corporation's continued success.

The Corporation's Enterprise Risk Management system establishes the infrastructure to allow the Corporation to predict and respond to risks and opportunities impacting our strategic direction and business activities and to do so in an effective, consistent and integrated manner. An annual business planning cycle enables continuous review of assumptions and the state of the market in which the Corporation operates.

Hydro Ottawa continues to monitor and manage traditional risks and sources of risk that are structural to the industry and the regulated environment. These include but are not restricted to: the weather; the policy and regulatory environment; the state of the economy and macro-economic trends; government policies relating to the production and procurement of renewable and clean energy as well as carbon emissions and conservation; the convergence of information technology and operational technology; labour force demographics, with a particular emphasis on the renewal of human resources in the trades; and the impact of fiscal policies on customers. In combination, these sources of risk have the power to determine the evolution of the industry, which could in turn present new and emerging risks that need to be managed effectively.

POLICY AND REGULATORY ENVIRONMENT

Hydro Ottawa's businesses operate in a regulated environment. Business performance could be adversely affected by significant policy and regulatory changes, including but not limited to changes in rate regulation, policies relating to the production, procurement, pricing or sale of renewable and clean energy, carbon emissions, CDM, the consolidation of electrical utilities, or restrictions on utility service provision.

The OEB approves local electricity distribution rates based on projected load growth and consumption levels. Hydro Ottawa Limited will be seeking OEB approval for a rebasing of its distribution rates for the 2016-2020 timeframe. The proposed new rates are premised upon forecasts of peak demand for electricity ['load'] and energy consumption. If regulatory approval is not forthcoming to the implementation of the projected rates, the Corporation's capacity to maintain and operate the electrical distribution system reliably and safely, retain customer satisfaction and invest in its distribution infrastructure could be affected, along with its net income. Financial results may also be affected if actual loads and energy consumption are not in keeping with forecast.

In the province of Ontario, prolonged uncertainty in policy direction on the consolidation and integration of local distribution companies could affect opportunities for growth.

AGING DISTRIBUTION INFRASTRUCTURE

Hydro Ottawa has developed a long-term Asset Management Plan to phase in the investments required to replace its aging distribution infrastructure, and maintain high standards of reliability and operability, while keeping pace with the growth of its service territory. Aging electricity assets pose a dual risk to LDCs. Apart from being more prone to failure [during extreme weather events, for example], they make restoration of the distribution system more complex and financially onerous.

As a member of the Municipal Electric Association Reciprocal Insurance Exchange, the Corporation is liable for additional assessments if premiums and reserves are not sufficient to cover costs such as claims. The Corporation is exposed to the claims risk of all members of this exchange.

ECONOMY

The state of the local and national economy could have a significant impact on the Corporation's business performance, through factors such as interest rates, inflation, customer credit risk, weakening demand for electricity and/or value-added services, and availability of market capital to fund growth. The economic climate could also have an effect on the stability and performance of some of Hydro Ottawa's key business partners.

CREDIT RATINGS

Significant future changes in macro-economic policy direction and emerging business or financial risks could affect the Corporation's existing credit rating of A/Stable.

DEPENDENCE ON PARTNERS

Current and future growth opportunities may depend upon the presence of willing partners, capable of performing to long-term expectations. The absence of municipalities willing to partner on utility service delivery, or of willing partners for mergers and acquisitions, or the underperformance of key business partners, could have a negative impact on Hydro Ottawa's ability to meet its growth objectives.

PENSION PLANS

The Corporation provides a defined benefit pension plan for the majority of its employees, through the OMERS. As OMERS is a multi-employer, contributory, defined benefit pension plan, it is not practicable to determine the Corporation's portion of pension obligations or the fair value of plan assets. OMERS' future funding shortfalls and net losses, if any, may entail contribution increases from both members and employers.

Hydro Ottawa has established a defined benefit pension plan for employees of Chaudiere Hydro L.P. and participating employers, with appropriate financial and investment procedures and oversight, as required by law. Pension benefit obligations and related net pension cost can be affected by volatility in the global financial and capital markets. There is no assurance that pension plan assets will earn the assumed long-term rates of return. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets.

TECHNOLOGY INFRASTRUCTURE

The Corporation's business performance is dependent upon complex technology systems, including customer information and billing systems, advanced metering, and operational technologies such as geographic information systems, system control and outage management systems. Increasing automation, the integration of systems, and extensive use of common technology in facilitating such integration and connectivity present emerging risks that the Corporation must manage effectively. The failure of one or more of these key systems, or a failure of the Corporation to plan effectively for future technology needs or transition effectively to new technology systems could adversely impact the Corporation's business operations.

CYBER SECURITY

The Corporation's reliance on information systems and expanded data transmission and exchange networks, in conjunction with the growing extent of systems and data integration within the electricity sector, increases its exposure to information security threats, including cyber security risks. A security breach, data corruption or system failure at a shared resource or common service provider, could put Hydro Ottawa's information systems and information assets at risk.

TIME-OF-USE TECHNOLOGY

Given the number of devices, systems and web interfaces involved in the smart meter – TOU billing process, as well as the number of external and internal service providers engaged, risks arising from the reliability and performance of any single component of this integrated network or of the system as a whole could lead to a disruption of the meter-to-cash cycle.

CUSTOMER, MEDIA PERCEPTIONS

Electrical utilities across Ontario are confronted with risks arising from negative customer and media perceptions. These risks might become more prominent in the context of Hydro Ottawa's application to the OEB for a rebasing of its rates for the years 2016-2020.

LABOUR FORCE DEMOGRAPHICS

Across the electricity sector, retirements are outpacing new entrants to the workforce, which could have an adverse impact on the ability of the Corporation to build a sustainable workforce and achieve its business objectives. Hydro Ottawa's investments in apprenticeships, internships, diversity, succession planning and retiree and older worker engagement programs are designed to manage risks relating to workforce demographics.

WEATHER

Severe weather can significantly impact financial results. Storms increase capital and maintenance costs to repair or replace damaged equipment and infrastructure, to ensure the continuing reliability of the electricity distribution system. Weather fluctuations also influence distribution revenues, which tend to increase with severe weather and decrease with moderate weather, and renewable energy production, which depends upon factors such as water flows [hydroelectric], and sun [solar].

OUTLOOK

Subject to the risks and uncertainties discussed in this document, Hydro Ottawa will continue to provide efficient, reliable electricity distribution services to customers at a competitive cost, generate green power, and provide energy services and conservation expertise while maintaining sustainable earnings. The Corporation will achieve this by continuing to invest in core distribution assets, improving productivity and pursuing business growth opportunities that leverage corporate strengths.

The Corporation also continues to actively pursue opportunities for expansion in non-regulated business lines in accordance with the endorsed strategy, as evidenced by the attainment of a long-term power purchase agreement and the upcoming expansion of generation facilities at Chaudière Falls.

Consolidated Financial Statements

December 31, 2014

TABLE OF CONTENTS

Report of Management

Management is responsible for the integrity of the financial data reported by Hydro Ottawa Holding Inc. ['the Corporation']. Fulfilling this responsibility requires the preparation and presentation of consolidated financial statements using management's best judgment and estimates in accordance with Canadian generally accepted accounting principles, applied on a basis consistent with the preceding year.

Management maintains appropriate systems of internal control and corporate-wide policies and procedures, which provide reasonable assurance that the Corporation's assets are safeguarded and that financial records are relevant and reliable.

The Board of Directors, through the Audit Committee, ensures that management fulfills its responsibility for financial reporting and internal control. The Audit Committee consists of outside directors and, at regular meetings, reviews audit, internal control and financial reporting matters with management and external auditors. The Audit Committee has reviewed the consolidated financial statements and submitted its report to the Board of Directors.

On behalf of Management,

Bryce Conrad
President and Chief Executive Officer

Geoff Simpson
Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Hydro Ottawa Holding Inc.

We have audited the accompanying consolidated financial statements of **Hydro Ottawa Holding Inc.**, which comprise the consolidated balance sheet as at December 31, 2014, and the consolidated statements of income, comprehensive income and retained earnings, and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **Hydro Ottawa Holding Inc.** as at December 31, 2014, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ottawa, Canada,
April 23, 2015

Chartered Professional Accountants
Licensed Public Accountants

Hydro Ottawa Holding Inc.

Consolidated Statement of Income, Comprehensive Income and Retained Earnings
Year ended December 31
[in thousands of Canadian dollars]

	2014	2013
Revenue		
Power recovery [Note 24]	**$ 799,272**	$ 768,079
Distribution sales [Note 24]	**156,616**	152,392
Generation revenue	**19,617**	21,047
Other revenue [Note 24]	**36,844**	34,849
	1,012,349	976,367
Expenses		
Purchased power	**795,703**	765,151
Operating costs [Note 24]	**123,258**	114,291
Depreciation	**33,120**	31,891
Amortization	**6,509**	8,431
	958,590	919,764
Income before other expenses and payments in lieu of corporate income taxes	**53,759**	56,603
Financing costs [Note 20]	**17,401**	14,645
Impairment charges [Notes 7 and 8]	**4,023**	-
	21,424	14,645
Income before payments in lieu of corporate income taxes	**32,335**	41,958
Payments in lieu of corporate income taxes [Note 21]	**1,812**	9,410
Net income and comprehensive income	**30,523**	32,548
Attributable to non-controlling interest [Note 18]	**205**	406
Attributable to equity shareholder	**30,318**	32,142
Retained earnings, beginning of year	**153,273**	138,242
Dividends declared and paid [Note 17]	**(19,300)**	(18,600)
Recovery of refundable dividend taxes paid [Note 17]	**-**	1,489
Retained earnings, end of year	**$ 164,291**	$ 153,273

The accompanying notes are an integral part of these consolidated financial statements

Hydro Ottawa Holding Inc.

Consolidated Balance Sheet
As at December 31
[in thousands of Canadian dollars]

	2014	2013
Assets		
Current assets		
Accounts receivable [Notes 4 and 24]	**$ 72,390**	$ 70,826
Payments in lieu of corporate income taxes receivable	**4,298**	2,372
Unbilled revenue [Note 5]	**81,806**	106,551
Prepaid expenses	**1,031**	3,099
Regulatory assets [Note 6]	**31**	31
Future income tax assets [Note 21]	**1,015**	818
	160,571	183,697
Non-current assets		
Regulatory assets [Note 6]	**20,592**	12,441
Property, plant and equipment [Note 7]	**780,397**	725,493
Intangible assets [Note 8]	**86,802**	66,289
Future income tax assets [Note 21]	**11,103**	19,947
Retirement benefit asset [Note 14]	**828**	689
Total assets	**1,060,293**	1,008,556
Liabilities and shareholder's equity		
Current liabilities		
Bank indebtedness [Note 9]	**15,955**	8,853
Accounts payable and accrued liabilities [Notes 10 and 24]	**175,850**	132,898
Payments in lieu of corporate income taxes payable	**1**	157
Regulatory liabilities [Note 6]	**-**	19,173
Notes payable [Note 15]	**925**	340
Regulatory liability for future income tax assets [Note 21]	**1,015**	818
	193,746	162,239
Non-current liabilities		
Regulatory liabilities [Note 6]	**22,141**	12,915
Regulatory liability for future income tax assets [Note 21]	**11,055**	19,893
Employee future benefits [Note 14]	**10,419**	9,065
Notes payable [Note 15]	**403,208**	400,413
Future income tax liabilities [Note 21]	**6,800**	6,464
Customer deposits	**12,459**	13,085
Other liabilities [Note 11]	**2,394**	329
	662,222	624,403
Shareholder's equity		
Share capital [Note 17]	**228,453**	228,453
Retained earnings	**164,291**	153,273
Non-controlling interest [Note 18]	**5,327**	2,427
	398,071	384,153
Total liabilities and shareholder's equity	**$ 1,060,293**	$ 1,008,556

Contingent liabilities and commitments [Notes 22 and 23]

ON BEHALF OF THE BOARD:

Director

Director

The accompanying notes are an integral part of these consolidated financial statements

Hydro Ottawa Holding Inc.

Consolidated Statement of Cash Flows
Year ended December 31
[in thousands of Canadian dollars]

	2014	2013
Net inflow (outflow) of cash related to the following activities:		
Operating		
Net income and comprehensive income	**$ 30,523**	$ 32,548
Items not affecting cash		
Depreciation	**33,120**	31,891
Amortization	**6,509**	8,431
Loss on disposal of capital assets [Notes 7 and 8]	**2,108**	1,083
Allowance for funds used during construction [Notes 7 and 8]	**(1,857)**	(2,411)
Future payments in lieu of corporate income taxes	**342**	1,288
Amortization of debt-issuance costs	**245**	237
Employee future benefits [Notes 6 and 14]	**77**	107
Change in retirement benefit asset [Note 14]	**(139)**	(215)
Impairment charges [Note 7]	**4,023**	-
Changes in non-cash working capital and other operating balances		
(Increase) decrease in accounts receivable [Note 7]	**(1,511)**	5,132
Decrease (increase) in unbilled revenue	**24,745**	(16,616)
Decrease (increase) in prepaid expenses	**2,068**	(446)
Increase in other liabilities [Note 11]	**2,169**	-
Increase in regulatory assets, net of liabilities [Notes 6 and 14]	**(16,775)**	(14,949)
Increase in accounts payable and accrued liabilities [Notes 7, 8 and 14]	**25,049**	3,296
(Increase) decrease in payments in lieu of corporate income tax balances [Note 17]	**(2,082)**	54
	108,614	49,430
Investing		
Acquisition of property, plant and equipment [Note 7]	**(114,284)**	(112,299)
Acquisition of intangible assets [Note 8]	**(11,484)**	(23,069)
Proceeds from disposal of property, plant and equipment and contribution rebates [Note 8]	**998**	1,765
Contributions in aid of construction [Note 7]	**23,625**	21,419
	(101,145)	(112,184)
Financing		
Proceeds from bond issuance, net of debt-issuance costs [Note 15]	**-**	148,857
Issuance of notes payable [Note 15]	**3,295**	-
(Decrease) increase in customer deposits [Notes 10 and 11]	**(1,090)**	435
Dividends paid [Note 17]	**(19,300)**	(18,600)
Repayment of notes payable [Note 15]	**(160)**	(420)
Repayable grant [Note 7]	**(10)**	(12)
Contributed capital from non-controlling interest [Note 18]	**2,694**	998
	(14,571)	131,258
Net change in cash	**(7,102)**	68,504
Bank indebtedness, beginning of year	**(8,853)**	(77,357)
Bank indebtedness, end of year	**$ (15,955)**	$ (8,853)
Supplemental cash flow information		
Interest paid	**$ 18,750**	$ 16,864
Payments in lieu of corporate income taxes paid	**$ 1,208**	$ 7,858

The accompanying notes are an integral part of these consolidated financial statements

Hydro Ottawa Holding Inc.

Notes to the Consolidated Financial Statements
December 31, 2014
[in thousands of Canadian dollars]

1. DESCRIPTION OF BUSINESS

Hydro Ottawa Holding Inc. ['Hydro Ottawa' or the 'Corporation'] was incorporated on October 3, 2000 pursuant to the *Business Corporations Act (Ontario)* as mandated by the Ontario government's *Electricity Act, 1998*. The Corporation is wholly owned by the City of Ottawa [the 'Shareholder']. The Corporation owns 100% of Hydro Ottawa Limited, Energy Ottawa Inc. ['Energy Ottawa'] and Telecom Ottawa Holding Inc. ['TOHI'] which does not maintain active operations.

Hydro Ottawa Limited is a regulated electricity distribution company that owns and operates electricity infrastructure in the City of Ottawa and the Village of Casselman and is responsible for the safe, reliable delivery of electricity to homes and businesses in its licensed service area. In addition to billing for distribution services, Hydro Ottawa Limited invoices customers for amounts it is required to pay to other organizations in Ontario's electricity system for providing wholesale generation and transmission services and for debt retirement.

Energy Ottawa is a power generation company that generates renewable energy. Energy Ottawa also offers a range of expert energy management and procurement services to large energy-consuming organizations and companies. Energy Ottawa holds interests in the following entities:

- Chaudiere Hydro L.P. was formed on June 22, 2012 and is over 99.99% owned by Energy Ottawa and less than 0.01% owned by Chaudiere Hydro Inc. ['Chaudiere Hydro GP']. Chaudiere Hydro L.P. was formed to own and operate three hydroelectric generation plants and related assets acquired in 2012. Chaudiere Hydro GP is wholly owned by Energy Ottawa and was incorporated on June 18, 2012 to act as the general partner of Chaudiere Hydro L.P.

- Moose Creek Energy LP ['Moose Creek LP'] is a 50.10% owned joint venture formed on April 15, 2011 to facilitate the construction and operation of a generation plant and gas collection system at the Laflèche landfill site in Moose Creek, Ontario. Moose Creek Energy Inc., a 50.00% owned joint venture incorporated on March 2, 2011, is the general partner of Moose Creek LP. Commercial operations of Moose Creek LP commenced on January 25, 2013.

- PowerTrail Inc. ['PowerTrail'] is a 60.00% owned joint venture incorporated on August 10, 2005 to construct and operate a generation plant and gas collection system at the Trail Road landfill site in Ottawa, Ontario.

- Chaudiere Water Power Inc. ['CWPI'] is a 66.67% owned joint venture incorporated on April 30, 1981 to act as an agent for the three principals of CWPI with a mandate to operate the Chaudière Dam facilities on the Ottawa River. The facilities are not owned by CWPI; they are jointly owned by the principals. In accordance with the shareholders' agreement, all expenses incurred by CWPI directly related to the facilities are fully reimbursed in accordance with each principal's ownership percentage.

- 2425932 Ontario Inc. is a wholly owned subsidiary formed on July 9, 2014, which does not maintain active operations.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with Part V of the *Chartered Professional Accountants of Canada Handbook* for publicly accountable entities ['pre-changeover Canadian GAAP'], including principles prescribed by the Ontario Energy Board ['OEB'] in the *Accounting Procedures Handbook* ['AP Handbook']. In the opinion of management, all adjustments necessary for fair presentation are reflected in the consolidated financial statements. The consolidated financial statements reflect the significant accounting policies summarized below.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(a) Basis of consolidation

The consolidated financial statements include the accounts of the Corporation and its subsidiaries: Hydro Ottawa Limited, Telecom Ottawa Holding Inc., and Energy Ottawa, which includes the accounts of PowerTrail, Moose Creek LP, Chaudiere Hydro L.P., Chaudiere Hydro GP, CWPI and 2425932 Ontario Inc. All intercompany balances and transactions have been eliminated in these consolidated financial statements.

(b) Consolidation of variable interest entities

The Corporation consolidates variable interest entities ['VIEs'] in which the Corporation is the primary beneficiary, as described in pre-changeover Canadian GAAP Accounting Guideline 15 – *Consolidation of Variable Interest Entities* ['AcG-15']. Upon the application of AcG-15, the initial equity investment at risk continues to not be sufficient to permit PowerTrail, Moose Creek LP or CWPI to finance their activities without additional subordinated financial support from its equity owners and, as such, these entities are consolidated in the consolidated financial statements of Energy Ottawa and ultimately, the Corporation.

The VIEs have non-controlling interests which are reported separately as part of equity.

(c) Investment in joint venture

The Corporation holds a 50.00% interest in Moose Creek GP, the general partner of Moose Creek LP. As general partner, Moose Creek GP has the full and exclusive right, power and authority to manage, control, administer and operate the business and affairs regarding the undertaking and business of Moose Creek LP. The other 50.00% is owned by Integrated Gas Recovery Services Inc. ['IGRS'] of Thorold, Ontario. While the Corporation accounts for its interest in Moose Creek GP using proportionate consolidation, Moose Creek GP does not contain significant assets, liabilities, revenue or expenses.

(d) Acquisition of assets and business combinations

The Corporation evaluates the integrated set of activities [inputs, processes, outputs] associated with an acquired asset group to determine whether it meets the definition of a business as prescribed by Section 1582 *Business Combinations* under pre-changeover Canadian GAAP. The consideration for an acquisition is measured at the aggregate of the fair values, at the date of exchange, of the assets transferred and the liabilities incurred to former owners of the acquired business in exchange for control of the acquired business. If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Corporation will report in its consolidated financial statements provisional amounts for the items for which the accounting is incomplete. Within one year, the Corporation will retrospectively adjust the provisional amounts recognized at the acquisition date to reflect new information obtained about facts and circumstances that existed as of the acquisition date and, if known, would have affected the measurement of the amounts recognized as at that date.

Transaction costs with respect to a business combination are expensed as incurred and included in general and administrative expenses as part of operating costs.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(e) Measurement uncertainty

The preparation of consolidated financial statements in conformity with pre-changeover Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of revenue, expenses, assets, liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Accounts receivable and unbilled revenue are reported net of an appropriate allowance for doubtful accounts ['AFDA']. Other significant estimates are used in determining the useful lives and asset impairments of long-lived assets, payments in lieu of corporate income taxes, employee future benefits, the retirement benefit asset, capital contribution obligations, certain accruals, as well as the fair value of assets and liabilities acquired.

Due to the inherent uncertainty involved in making such estimates, actual results could differ from estimates recorded in preparing these consolidated financial statements, including changes as a result of future decisions made by the OEB or the provincial government. The consolidated financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the significant accounting policies.

(f) Regulation

Hydro Ottawa Limited is regulated by the OEB under the authority of the *Ontario Energy Board Act, 1998*. The OEB is charged with the responsibilities of approving or setting rates for the transmission and distribution of electricity, and ensuring that distribution companies fulfil obligations to connect and service customers.

Hydro Ottawa Limited operates under an incentive regulation mechanism ['IRM'] prescribed by the OEB. Under IRM, a distributor first sets base rates through a cost-of-service application every four years. This application determines the appropriate revenue requirement to recover approved costs, and provides a rate of return on a deemed capital structure applied to approved rate base assets. For subsequent years in which no cost-of-service application is filed, rates are adjusted by an inflation factor less a productivity factor.

Hydro Ottawa Limited applies for distribution rates based on estimated costs of service. Once the rate is approved, it is not adjusted as a result of actual costs of service being different from those which were estimated, other than for certain prescribed costs that are eligible for deferral treatment and are either collected or refunded in future rates. The OEB has the general power to include or exclude costs and revenue in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company.

Hydro Ottawa Limited continues to assess the likelihood of recovery of all regulatory assets subject to recovery through a future rate filing. The absence of OEB approval is a consideration in this evaluation. If the requirement for a provision becomes more likely than not, the Corporation will recognize the provision in operating costs for the year.

The following regulatory treatments have resulted in accounting treatments that differ from pre-changeover Canadian GAAP for enterprises operating in a non-regulated environment:

(i) Regulatory assets and liabilities

Regulatory assets primarily represent costs that have been deferred because it is probable that they will be recovered in future rates. Similarly, regulatory liabilities can arise from differences in amounts billed to customers for electricity services and the costs that Hydro Ottawa Limited incurs to purchase these services.

Hydro Ottawa Limited accrues interest on the regulatory asset and liability balances as directed by the OEB.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(f) Regulation [continued]

(i) Regulatory assets and liabilities [continued]

Regulatory assets and liabilities are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months after the reporting period. All other regulatory asset and liability balances are classified as long-term on the consolidated balance sheet.

Regulatory balances are comprised principally of the following:

- Regulatory asset/liability refund account ['RARA' / 'RLRA'] consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through temporary additional rates referred to as rate riders.

- Settlement variances relate primarily to the charges Hydro Ottawa Limited incurred for transmission services, the commodity, wholesale market operations and the global adjustment that were not settled with customers during the year. The nature of the settlement variances is such that the balance can fluctuate between assets and liabilities over time and they are reported at year end dates in accordance with rules prescribed by the OEB.

- Deferred smart meter costs represent the differences between the amounts funded through rates for smart meters and actual program costs. Program costs include operating, maintenance, depreciation and administrative expenses directly related to smart meters and a return on smart meter assets.

- Stranded meter costs represent the net book value of conventional meters removed upon the installation of smart meters.

- Other Post–Employment Benefits deferral account ['OPEB deferral account'] was authorized by the OEB in 2011 to record the adjustment to post-retirement benefits relating to the cumulative actuarial gains or losses. This account is adjusted annually to record any changes in the cumulative actuarial gains or losses. No interest charges are recorded on this account as instructed by the OEB.

Other regulatory variances and deferred costs:

- The OEB allows electricity distributors to record in a deferral account the difference between low voltage charges paid to Hydro One Networks Inc. ['HONI'] and those charged to customers.

- The OEB allows electricity distributors to record in a deferral account the net cost of providing retailer billing services and transaction request services.

- The OEB approved a deferral account for distributors to record one-time administrative incremental International Financial Reporting Standards ['IFRS'] transition costs, which were not already approved and included for recovery in distribution rates.

- In its Guidelines released June 16, 2009, the OEB created four new deferral accounts to allow distributors to begin recording expenditures for certain activities relating to the connection of renewable generation and the development of a smart grid. These deferral accounts were authorized to be used to record qualifying incremental capital investments or operating, maintenance and administrative expenses.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(f) Regulation [continued]

(i) Regulatory assets and liabilities [continued]

- In its Guidelines released January 5, 2012, the OEB required Hydro Ottawa Limited to record the difference between the actual authorized Conservation and Demand Management ['CDM'] activities and activities included in Hydro Ottawa Limited's load forecast. This variance is recorded in the Lost Revenue Adjustment Mechanism variance account.

- The OEB directed distributors to record the input tax credit savings arising from the elimination of the provincial sales tax and implementation of the harmonized sales tax on July 1, 2010 in a separate account. The OEB concluded that fifty percent of the balances should be returned to the ratepayers for the period up to the rebasing date, which for Hydro Ottawa Limited was January 1, 2012.

(ii) Contributions in aid of construction

Contributions in aid of construction received from outside sources are used to finance additions to property, plant and equipment. According to the AP Handbook, contributions in aid of construction are treated as a reduction to property, plant and equipment and are depreciated at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

(iii) Allowance for funds used during construction ['AFUDC']

An allowance for the cost of funds used during the construction period has been applied to major capital and development projects.

(iv) Payments in lieu of corporate income taxes ['PILs']

Hydro Ottawa Limited is considered to be a Municipal Electric Utility ['MEU'] for purposes of the PILs regime contained in the *Electricity Act, 1998*, as all of its share capital is indirectly owned by the City of Ottawa and not more than 10% of its income is derived from activities carried on outside the municipal boundaries of the City of Ottawa. The *Electricity Act, 1998* provides that a MEU that is exempt from tax under the *Income Tax Act (Canada)* ['ITA'] and the *Taxation Act, Ontario* ['TAO'] is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount approximating the tax that it would be liable to pay under the ITA and the TAO if it were not exempt from tax.

Hydro Ottawa Limited follows the liability method for recording income taxes in accordance with pre-changeover Canadian GAAP recommendations. Under the liability method, current income taxes payable are recorded based on taxable income. Future income taxes arising from temporary differences in the accounting and tax basis of assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

The AP Handbook provides for the recovery of PILs by Hydro Ottawa Limited through annual distribution rate adjustments as approved by the OEB. Hydro Ottawa Limited recognizes regulatory liabilities and assets for the amounts of future income taxes expected to be refunded to or recovered from customers in future electricity rates.

The Corporation, Energy Ottawa, Chaudiere Hydro GP, Telecom Ottawa Holding Inc. and 2425932 Ontario Inc. are also MEUs that account for PILs using the liability method.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(f) Regulation [continued]

(iv) Payments in lieu of corporate income taxes ['PILs'] [continued]

PowerTrail and CWPI are taxable under the ITA and TAO as less than 90% of each corporation's share capital is owned by the City of Ottawa. Corporate income taxes are accounted for using the liability method as described above.

Moose Creek LP and Chaudiere Hydro L.P. are not taxable entities for federal and provincial income tax purposes. Tax on the net income (loss) is borne by the individual partners through the allocation of taxable income.

(g) Revenue recognition

The Corporation recognizes revenue when persuasive evidence of an arrangement exists, services have been delivered, the price has been fixed or is determinable and collection is reasonably assured.

(i) Distribution sales

The Corporation charges customers for the delivery of electricity, based on rates established by the OEB. The rates are intended to allow the Corporation to recover its prudently incurred costs and earn a fair return on invested capital. Distribution sales are recognized when electricity is delivered to the customer, as measured by meter readings or usage estimates.

(ii) Power recovery

Power recovery revenue represents the pass-through of the cost of power to the consumer as purchased by the Corporation and is recognized when electricity is delivered to the customer, as measured by meter readings or usage estimates. Power recovery revenue is regulated by the OEB and includes charges to customers for the electricity commodity, the transmission of electricity and the administration of the wholesale electricity system.

(iii) Unbilled revenue

Unbilled revenue represents an estimate of the electricity consumed by customers that has not yet been billed as at year end.

(iv) Generation revenue

Generation revenue is recorded on the basis of regular meter readings.

(v) Other revenue

Other revenue related to the provision of services is recognized as services are rendered. Other revenue includes contract revenue, commercial services revenue and CDM revenue.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(g) Revenue recognition [continued]

(v) Other revenue [continued]

Contract revenue and commercial services revenue are accounted for using the percentage-of-completion method, whereby revenue and the corresponding costs are recognized proportionately with the degree of completion of the services under contract. Losses on contracts are fully recognized when they become evident. CDM revenue stems from the delivery of provincial government programs that promote conservation and is recognized on a cost-recovery basis.

(h) Bank indebtedness

Bank indebtedness includes short-term advances and/or bankers' acceptances with a maturity date of three months or less, and outstanding cheques.

(i) Financial instruments

All financial instruments are initially recorded at fair value, unless fair value cannot be reliably determined. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between willing parties. The subsequent measurement of each financial instrument depends on the classification elected by the Corporation.

The Corporation classifies and measures its financial instruments as follows:

- Cash is classified as held-for-trading and is measured at fair value.

- Accounts receivable and unbilled revenue are classified as loans and receivables and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value with the exception of related party transactions, which are measured at the carrying amount determined in accordance with pre-changeover Canadian GAAP Section 3840, *Related Party Transactions*. Subsequent measurements are recorded at amortized cost using the effective interest rate method, if applicable.

- Bank indebtedness, accounts payable and accrued liabilities, customer deposits, capital contribution obligations and notes payable are classified as other financial liabilities and are initially measured at their fair value with the exception of related party transactions, which are measured at the carrying amount determined in accordance with pre-changeover Canadian GAAP Section 3840, *Related Party Transactions*. Subsequent measurements are recorded at amortized cost using the effective interest rate method, if applicable.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(j) Property, plant and equipment

Property, plant and equipment consist principally of electricity distribution infrastructure, generating plant and equipment, buildings and fixtures, land, reservoirs, dams and waterways, furniture and equipment, and assets under construction. Property, plant and equipment acquired in a business combination are initially recorded at their acquisition date fair values.

Spare parts and standby equipment, which are expected to be used during more than one year, are considered to be assets under construction and are depreciated only once they are put into service.

Property, plant and equipment are recorded at cost and include directly attributable contracted services, materials, labour, engineering costs, overheads and AFUDC. Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers. Contributions in aid of construction received are treated as a contra account to property, plant and equipment. The amount is depreciated by a charge to accumulated depreciation and a reduction in depreciation expense at an equivalent rate to that used for the depreciation of the related asset.

Significant renewals and enhancements to existing assets are capitalized only if the service life of the asset is increased, reliability is improved above original design standards or if operating costs are reduced by a substantial and quantifiable amount.

Depreciation is recorded on a straight-line basis over the estimated service life of the related asset.

Estimated service lives for property, plant and equipment classes are as follows:

Buildings and fixtures	20 to 100 years
Furniture and equipment	5 to 10 years
Rolling stock	7 to 15 years
Electricity distribution infrastructure	10 to 60 years
Generating plant and equipment	3 to 50 years
Reservoirs, dams and waterways	75 to 125 years

Assets under construction, land, spare parts and standby equipment are not subject to depreciation.

The Corporation reviews its property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. If events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, the Corporation will estimate the future cash flows expected to result from the use of the asset group and their eventual disposition, and record an impairment loss, if required. The Corporation's primary measure of fair value is based on discounted cash flows.

(k) Intangible assets

Intangible assets include land rights, a power purchase agreement, capital contributions, computer software, water rights and assets under development.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(k) Intangible assets [continued]

Intangible assets with finite lives are recorded at cost and amortized on a straight-line basis over the estimated service life of the related asset. Intangible assets acquired in a business combination are initially recorded at their acquisition date fair values.

Estimated service lives for intangible assets with finite lives are as follows:

Land rights	50 years
Power purchase agreement	7 years
Capital contributions	45 years
Computer software	5 to 10 years

Water rights with respect to the Chaudière Dam on the Ottawa River, which has an indefinite useful life, and assets under development are not subject to amortization.

The Corporation reviews its intangible assets subject to amortization for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. If events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable, the Corporation will estimate the future cash flows expected to result from the use of the asset group and their eventual disposition, and record an impairment loss, if required. The Corporation's primary measure of fair value is based on discounted cash flows.

The Corporation reviews its intangible assets not subject to amortization annually for the possibility of impairment. Through this process, the assessment of indefinite life is reviewed to determine whether the indefinite life continues to be supportable. If not, the change in useful life from indefinite to finite is made on a prospective basis.

(l) Asset retirement obligations

The Corporation recognizes its obligation to retire certain tangible long-lived assets, whereby the fair value of a liability for an asset retirement obligation is recognized in the period during which it is incurred if a reasonable estimate can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and then amortized over its estimated useful life. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows. The liability is adjusted for an annual accretion charged to operating costs. A gain or loss may be incurred upon settlement of the liability.

(m) Employee future benefits

(i) Pension plans

The Corporation provides pension benefits for its employees through the Ontario Municipal Employees Retirement System ['OMERS'] Fund [the 'Fund']. OMERS is a multi-employer pension plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a defined benefit pension plan, which is financed by equal contributions from participating employers and employees and by the investment earnings of the Fund.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(m) Employee future benefits [continued]

(i) Pension plans [continued]

Although the plan is a defined benefit plan, sufficient information is not available to the Corporation to account for it as such because it is not possible to attribute the fund assets and liabilities between the various employers who contribute to the fund. As a result, the Corporation accounts for the plan as a defined contribution plan, and contributions payable as a result of employee service are expensed as incurred as part of operating costs.

Chaudiere Hydro L.P. is the sponsoring employer of the Pension Plan for Employees of Chaudiere Hydro L.P. and Participating Employers ['Chaudiere Pension Plan' or 'CHPP']. The CHPP is accounted for as follows:

- CHPP assets are assets that are held by an insurance corporation and are measured at fair value, which is based on published market mid-price information in the case of quoted securities.

- Accrued benefit obligations of the CHPP are determined based on the expected future benefit payments discounted using market interest rates on high-quality debt instruments that match the timing and amount of expected benefit payments.

- The cost of pension earned by employees is actuarially determined using the projected benefit method prorated on services, and management's best estimate of expected plan investment performance, salary escalation, retirement ages, life expectancy and health care costs.

- The actuarial gains and losses arising on the plan assets and defined benefit obligation are recognized into income in the year in which they occur using the immediate recognition approach.

- Past service costs are included in the cost of the CHPP for the year when they arise.

Since the CHPP is funded, the fair value of the Chaudiere Pension Plan assets is offset against the accrued benefit obligation. The net amount is included in the retirement benefit asset or retirement benefit liability.

(ii) Employee future benefits other than pension plans

Employee future benefits other than pensions provided by the Corporation include medical, dental and life insurance benefits, accumulated sick leave credits and a retirement grant. These plans provide benefits to certain employees when they are no longer providing active service.

Employee future benefits expense is recognized in the period during which the employees render services.

Employee future benefits are recorded on an accrual basis. The accrued benefit obligation and current service costs are calculated using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Actuarial gains and losses resulting from experience different from that assumed or from changes in actuarial assumptions are recognized in income immediately. However, for Hydro Ottawa Limited, these amounts are deferred as a regulatory asset or liability as permitted by the OEB.

2. SIGNIFICANT ACCOUNTING POLICIES [CONTINUED]

(n) Customer deposits

Customer deposits are cash collections from customers to guarantee the payment of energy bills and fulfillment of construction obligations. Deposits estimated to be refundable to customers within the next fiscal year are classified as current liabilities and included in accounts payable and accrued liabilities.

(o) Leases

At the inception of a lease, or an arrangement that contains a lease, the Corporation evaluates whether the lease should be classified as a capital lease or an operating lease. Leases that transfer substantially all the risks and rewards incidental to ownership of the related asset are classified as capital leases. All other leases are classified as operating leases. Classification is reassessed if the terms of the lease are changed.

Upon evaluation, all of the Corporation's leases are classified as operating leases.

(p) Debt-issuance costs

The Corporation incurred debt issuance costs that were external, direct and incremental in nature arising from its debenture offerings and credit facility restructuring. Debt issuance costs are netted against the proceeds of debt and amortized using the effective yield method. Credit facility restructuring costs are amortized over the initial term of the revolving term credit facility.

3. FUTURE CHANGES IN ACCOUNTING POLICIES

On February 13, 2008, the Canadian Accounting Standards Board ['AcSB'] confirmed that publicly accountable enterprises ['PAEs'] would be required to transition to IFRS effective January 1, 2011. While the Corporation is not a PAE, it is a Government Business Enterprise given its status as a municipally owned utility, and such enterprises are required to follow the same basis of accounting as PAEs.

On the original transition date, IFRS did not contain a standard governing rate-regulated activities ['RRA']. Due to the significance of this issue in Canada, the AcSB postponed the original IFRS transition date to January 1, 2015 for qualifying entities with RRA pending the completion of an interim standard by the International Accounting Standards Board ['IASB']. Until January 1, 2015, qualifying entities are permitted to continue reporting under pre-changeover Canadian GAAP.

On January 30, 2014, the IASB issued interim standard IFRS 14 – Regulatory Deferred Accounts ['IFRS 14'] which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices. This standard becomes effective January 1, 2016 with early adoption permitted. The Corporation adopted IFRS and early adopted IFRS 14 on January 1, 2015. The Corporation has assessed the implications of adopting IFRS and is currently reviewing its impact on the financial reporting.

Hydro Ottawa Holding Inc.

Notes to the Consolidated Financial Statements
December 31, 2014
[in thousands of Canadian dollars]

4. ACCOUNTS RECEIVABLE

		2014		2013
Electricity receivables, net of AFDA of $3,602 [2013 – $1,370] [Note 19b]	$	**47,605**	$	50,965
Other receivables, net of AFDA of $75 [2013 – $66] [Note 19b]		**15,999**		11,955
Amounts due from related parties [Note 24]		**8,786**		7,906
	$	**72,390**	$	70,826

5. UNBILLED REVENUE

		2014		2013
Unbilled revenue	$	**81,957**	$	106,757
Less AFDA [Note 19b]		**(151)**		(206)
	$	**81,806**	$	106,551

6. REGULATORY ASSETS AND LIABILITIES

The Corporation files a rate application to settle its regulatory assets and liabilities as required. The time period for settlement is determined by the OEB based on the magnitude of the balances to be cleared.

Information about the Corporation's regulatory assets and liabilities is as follows:

		2014		2013
Regulatory assets				
OPEB deferral account [Note 14]	$	**4,432**	$	3,109
Settlement variances		**12,224**		5,527
RARA		**208**		475
Other		**3,759**		3,361
		20,623		12,472
Less current portion		**(31)**		(31)
Total non-current regulatory assets	$	**20,592**	$	12,441

6. REGULATORY ASSETS AND LIABILITIES [CONTINUED]

	2014	2013
Regulatory liabilities		
Settlement variances	**$ 14,414**	$ 27,374
Stranded meters	**2,987**	-
Smart meters	**-**	1,045
RLRA	**3,143**	2,002
Other	**1,597**	1,667
	22,141	32,088
Less current portion	**-**	(19,173)
Total non-current regulatory liabilities	**$ 22,141**	$ 12,915

(a) Regulatory asset/liability refund accounts

The RARA/RLRA is the net aggregate of all regulatory assets and liabilities which have been approved for recovery or disposition and includes accrued interest costs up to December 31, 2014 of $174 [2013 – $178] less amounts already settled through distribution rates.

(b) Settlement variances

Settlement variances include accrued interest costs of $19 [2013 – $284].

(c) Other

Other variance and deferred costs include accrued interest earned of $48 [2013 – $34].

(d) Income before PILs

In the absence of rate regulation, the income before PILs for the year ended December 31, 2014 would be lower by $18,098 [2013 – lower by $13,052].

Hydro Ottawa Holding Inc.

Notes to the Consolidated Financial Statements
December 31, 2014
[in thousands of Canadian dollars]

7. PROPERTY, PLANT AND EQUIPMENT

	2014		
	Cost	**Accumulated depreciation**	**Net book value**
Land	**$ 31,252**	**$ -**	**$ 31,252**
Buildings and fixtures	**88,604**	**25,124**	**63,480**
Furniture and equipment	**13,130**	**6,935**	**6,195**
Rolling stock	**25,607**	**14,860**	**10,747**
Electricity distribution infrastructure	**1,201,881**	**447,516**	**754,365**
Generating plant and equipment	**53,755**	**14,295**	**39,460**
Reservoirs, dams and waterways	**24,619**	**1,865**	**22,754**
Assets under construction	**55,462**	**-**	**55,462**
	1,494,310	**510,595**	**983,715**
Contributions in aid of construction	**(257,943)**	**(54,625)**	**(203,318)**
	$ 1,236,367	**$ 455,970**	**$ 780,397**

	2013		
	Cost	Accumulated depreciation	Net book value
Land	$ 31,252	$ -	$ 31,252
Buildings and fixtures	87,132	22,588	64,544
Furniture and equipment	18,121	11,895	6,226
Rolling stock	24,754	15,455	9,299
Electricity distribution infrastructure	1,131,820	437,739	694,081
Generating plant and equipment	55,517	12,737	42,780
Reservoirs, dams and waterways	19,972	1,671	18,301
Assets under construction	44,947	-	44,947
	1,413,515	502,085	911,430
Contributions in aid of construction	(234,318)	(48,381)	(185,937)
	$ 1,179,197	$ 453,704	$ 725,493

During the year, the Corporation capitalized an AFUDC of $1,286 [2013 – $1,330] to property, plant and equipment and credited financing costs [Note 20]. The average annual interest rate for 2014 was 4.6% [2013 – 4.5%].

The Corporation entered into significant non-cash transactions that have been excluded from the consolidated statement of cash flows. These transactions were related to property, plant and equipment additions of $13,353 [2013 – $11,485] which are included in accounts payable and accrued liabilities and $53 [2013 – nil] of contributions receivable towards additions which are included in accounts receivable as at December 31, 2014.

During the year, the Corporation incurred a loss on disposal of property, plant and equipment of $1,934 [2013 – $1,083].

7. PROPERTY, PLANT AND EQUIPMENT [CONTINUED]

On February 7, 2014, the Corporation's subsidiary Chaudiere Hydro L.P. was granted a forty year Hydroelectric Standard Offer Program – Municipal Stream Contract ['HESOP Contract'] by the OPA to produce renewable waterpower. As a result of this opportunity, the Corporation has embarked on a multi-year project to expand its Ontario generation facilities ['the Ontario Group'] at Chaudière Falls increasing its total capacity from 38 megawatts to 58 megawatts. The anticipated commercial operation date is in 2017 and the Corporation plans to invest significant resources on this expansion over the next three years ['Chaudiere Expansion'].

To allow for the construction of the new hydroelectric generation facility, Chaudiere Hydro L.P. must permanently decommission the two Ontario generating stations at Chaudière Falls in July 2015. Consequently, the Corporation has recorded impairment charges of $4,023 against the Ontario Group, of which $2,787 relates to generating plants and equipment while the remaining $1,236 pertains to the power purchase agreement with Hydro Québec [Note 8] as the new facility will operate under the new HESOP Contract instead. Impairment charges recorded with respect to the Ontario Group have reduced its carrying value to fair value as at December 31, 2014, which is based on discounted cash flows. There was no impairment of property, plant and equipment for the year ended December 31, 2013.

In 2005, Energy Ottawa entered into an agreement with the Federal Government's Department of Natural Resources whereby project funding of up to $220 was provided to Energy Ottawa to field trial a mini hydro turbine developed by the Canada Centre for Mineral and Energy Technology ['CANMET'] Small Hydro Program. Under the terms of the agreement, an amount up to $150 of the funding received is repayable at a rate of 2.5% of revenue received from the project, over a maximum period of 10 years from the operation commencement date of the turbine [2007]. As at December 31, 2014, the unamortized balance of the non-repayable funding received of $38 [2013 – $41] is included in contributions in aid of construction. The current portion of the remaining repayable balance amounts to $10 [2013 – $12] and is included in accounts payable and accrued liabilities, while the long-term portion in the amount of $19 [2013 – $29] is included in other liabilities.

8. INTANGIBLE ASSETS

	2013	Acquisitions (net of transfers)	Retirements	2014
Cost				
Land rights	$ 3,137	$ 11	$ -	$ 3,148
Power purchase agreement	4,578	-	(1,873)	2,705
Capital contributions	4,134	637	(77)	4,694
Computer software	60,975	33,248	(29,408)	64,815
Water rights	16,941	-	-	16,941
Assets under development [Note 13]	33,936	(5,561)	-	28,375
	$ 123,701	$ 28,335	$ (31,358)	$ 120,678

8. INTANGIBLE ASSETS [CONTINUED]

	2013	Amortization	Retirements	2014
Accumulated amortization				
Land rights	$ 1,359	$ 48	$ -	$ 1,407
Power purchase agreement	781	700	(637)	844
Capital contributions	1,047	88	-	1,135
Computer software	54,225	5,673	(29,408)	30,490
	$ 57,412	$ 6,509	$ (30,045)	$ 33,876

	Cost	Accumulated amortization	Net book value
Net book value as at December 31, 2014			
Land rights	$ 3,148	$ 1,407	$ 1,741
Power purchase agreement	2,705	844	1,861
Capital contributions	4,694	1,135	3,559
Computer software	64,815	30,490	34,325
Water rights	16,941	-	16,941
Assets under development [Note 13]	28,375	-	28,375
	$ 120,678	$ 33,876	$ 86,802

	2012	Acquisitions (net of transfers)	Retirements	2013
Cost				
Land rights	$ 3,135	$ 2	$ -	$ 3,137
Power purchase agreement	4,578	-	-	4,578
Capital contributions	3,780	354	-	4,134
Computer software	64,073	2,167	(5,265)	60,975
Water rights	16,941	-	-	16,941
Assets under development	13,690	20,246	-	33,936
	$ 106,197	$ 22,769	$ (5,265)	$ 123,701

8. INTANGIBLE ASSETS [CONTINUED]

	2012	Amortization	Retirements	2013
Accumulated amortization				
Land rights	$ 1,310	$ 49	$ -	$ 1,359
Power purchase agreement	80	701	-	781
Capital contributions	977	70	-	1,047
Computer software	51,879	7,611	(5,265)	54,225
	$ 54,246	$ 8,431	$ (5,265)	$ 57,412

	Cost	Accumulated amortization	Net book value
Net book value as at December 31, 2013			
Land rights	$ 3,137	$ 1,359	$ 1,778
Power purchase agreement	4,578	781	3,797
Capital contributions	4,134	1,047	3,087
Computer software	60,975	54,225	6,750
Water rights	16,941	-	16,941
Assets under development	33,936	-	33,936
	$ 123,701	$ 57,412	$ 66,289

During the year, the Corporation capitalized an AFUDC of $571 [2013 – $1,081] to intangible assets and credited financing costs [Note 20]. The average annual interest rate for 2014 was 4.6% [2013 – 4.5%].

During the year, the Corporation incurred a loss on disposal of intangible assets of $174 [2013 – nil]. Also during the year, Moose Creek LP received a $77 credit against its original capital contribution incurred upon setting up its line connection at its landfill gas facility in 2011. Under the line connection agreement with HONI, Moose Creek LP becomes entitled to a percentage rebate of costs should any other parties connect to the newly created line, which occurred in 2014.

As described in Note 7, during the year, the Corporation recorded impairment charges [retirements] of $1,236 against the power purchase agreement with Hydro Québec. There was no impairment of intangible assets for the year ended December 31, 2013.

The Corporation entered into significant non-cash transactions that have been excluded from the consolidated statement of cash flows. These transactions were related to intangible asset additions of $17,183 [2013 – $729], which represent amounts included in accounts payable and accrued liabilities.

9. CREDIT FACILITY

During the year, the Corporation renewed its credit facility for a revised amount of $336,000 [December 31, 2013 – $193,500]. The facility continues to consist of a $75,000 [2013 – $75,000] 364-day revolving operating line and a $100,000 [2013 – $100,000] revolving line to fund capital expenditures and growth opportunities, both of which mature on August 1, 2017. In addition, the Corporation has a $10,000 [2013 – $17,500] line to fund letters of credit and other guarantees, a new $150,000 [2013 – nil] 364-day revolving operating line and a $1,000 [2013 – $1,000] commercial card facility — all of which mature on August 1, 2015. The revolving operating lines can be used by way of direct advances and/or bankers' acceptances, which can be continuously renewed with maturities of 7 to 180 days. This credit facility contains customary covenants and events of default including a covenant to maintain the consolidated tangible net worth in excess of $175,000 at all times. It also requires the debt to capitalization ratio to be at or below 75% on a consolidated basis.

As at December 31, 2014, the Corporation had drawn $37,000 in bankers' acceptances against its operating lines [2013 – $4,950 in direct advances]. The Corporation has also drawn $8,150 [2013 – $16,000] against its facilities in standby letters of credit.

PowerTrail maintains a credit facility for $200 [2013 – $200] in standby letters of credit to the Ontario Power Authority ['OPA']. The facility contains customary covenants and events of default, including a covenant to maintain a tangible net worth of $1,000. As at December 31, 2014, PowerTrail had drawn an amount of $133 [2013 – $133] in standby letters of credit against this facility.

Chaudiere Hydro L.P. has a standby letter of credit to the Receiver General of Canada on behalf of Fisheries and Oceans Canada in the amount of $538 [2013 - nil], expiring on October 23, 2015 in connection with the Chaudiere Expansion, and a standby letter of credit to the OPA in the amount of $587 [2013 - nil], expiring on February 23, 2016 in connection with the 40-year HESOP contract.

CWPI maintains a credit facility consisting of a $500 [2013 – $500] operating line secured by the three principals of CWPI. The operating credit line is repayable on demand, bears interest at the Bank of Canada's prime lending rate with interest payable monthly. The facility also contains customary covenants and events of default. CWPI has not drawn any funds against this line as at December 31, 2014 [December 31, 2013 – nil].

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2014	2013
Purchased power payable	**$ 89,681**	$ 67,033
Trade accounts payable and accrued liabilities	**49,952**	43,927
Customer deposits	**13,843**	14,307
Capital contribution obligations [Note 13]	**15,700**	-
Customer credit balances	**6,567**	7,363
Due to related parties [Note 24]	**107**	268
	$ 175,850	$ 132,898

11. OTHER LIABILITIES

		2014		2013
Non-current repayable grant [Note 7]	$	**19**	$	29
Asset retirement obligations [Note 12]		**206**		300
Other liabilities		**2,169**		-
	$	**2,394**	$	329

12. ASSET RETIREMENT OBLIGATIONS

		2014		2013
Balance, beginning of year	$	**300**	$	438
Liabilities settled during the year		**(104)**		(141)
Accretion expense		**-**		26
Revisions in estimated cash flows		**10**		(23)
	$	**206**	$	300

As at December 31, 2014 the Corporation estimates an asset retirement obligation ['ARO'] of $206 [2013 – $300] related to the removal and destruction of polychlorinated biphenyls ['PCBs'] in distribution transformers and other clean-up related to PCBs. The ARO is calculated using an estimated undiscounted cash flow over two years [2013 – two years] totalling $254 [2013 – $357] and a discount rate of 5.3% [2013 – 5.3%]. No assets have been legally restricted for settlement of the liability.

13. CAPITAL CONTRIBUTION OBLIGATIONS

The Corporation is party to various Connection and Cost Recovery Agreements ['CCRAs'] with HONI. These agreements govern the construction by HONI of new or modified transformer stations for the purpose of serving the Corporation's customers, including anticipated electricity load growth.

All terms and conditions of CCRAs follow the Transmission System Code [the 'Code'] issued by the OEB. The amount of the initial capital contribution required is based on the prescribed economic evaluation procedure set out in the Code. This initial capital contribution is reduced by any commitment of connection revenue [the 'guaranteed revenue'] earned by HONI from the Corporation over the period of the respective CCRA. Guaranteed revenue is calculated based on forecasted load ['initial load'] multiplied by HONI's approved rate at the time of entering into these agreements.

Each of the Corporation's CCRAs has a term 25 years. These agreements require periodic reviews whereby a comparison of actual to forecasted load is conducted, and a true-up calculation performed. When a true-up calculation shows the Corporation's actual load for the past period and updated load forecast for the future period is lower than the initial load, the Corporation is obligated to make up this shortfall. When the Corporation's actual load and updated load forecast is higher than the initial load, the Corporation is entitled to a rebate. True-up calculations are made in years 5 and 10 and in year 15 if the difference between the actual incremental load and initial load at the end of year 10 is greater than 20%.

13. CAPITAL CONTRIBUTION OBLIGATIONS [CONTINUED]

Based on a review of the Corporation's CCRAs with HONI, the Corporation estimates a shortfall in guaranteed revenue. As a result of such a shortfall, the Corporation has recorded a total capital contribution obligation and a corresponding intangible asset of $15,700 as at December 31, 2014 [2013 – nil]. The Corporation expects to settle its capital contribution obligations in 2015.

14. EMPLOYEE FUTURE BENEFITS

(a) Pension plans

The Corporation contributes to two defined benefit plans covering substantially all of its employees.

The Corporation's participating employer contributions under OMERS for the year ended December 31, 2014 amounted to $6,058 [2013 – $5,939].

On November 20, 2012, the Corporation, through its subsidiary Chaudiere Hydro L.P., completed an acquisition of generation assets from Domtar Inc. through an Agreement of Purchase and Sale ['Purchase Agreement']. On this date, the Corporation began providing retirement benefits to certain employees who transferred to the Corporation through the creation of the Chaudiere Pension Plan. In accordance with the Purchase Agreement, Domtar Inc. agreed to fund the actuarial plan obligations relating to the transferred employees as at November 20, 2012. On October 17, 2014, after review and approval by the Financial Services Commission of Ontario, the CHPP received a cash transfer of $4,640 for such funding. As an estimate of the fair value of plan assets to be received was made prior to the transfer, there is no significant impact to the Corporation's results.

(i) Accrued benefit obligation

		2014		2013
Balance, beginning of year	**$**	**3,593**	$	3,573
Current service cost		**235**		264
Interest cost on accrued benefit obligation		**180**		151
Benefit payments, net of administrative expenses		**(82)**		(102)
Actuarial losses (gains)		**613**		(293)
Balance, end of year	**$**	**4,539**	$	3,593

(ii) Plan assets

		2014		2013
Fair value, beginning of year	**$**	**4,282**	$	4,047
Actual return on plan assets		**868**		48
Employer contributions		**202**		190
Benefit payments and administrative expenses		**(82)**		(102)
Employee contributions		**97**		99
Fair value, end of year	**$**	**5,367**	$	4,282

14. EMPLOYEE FUTURE BENEFITS [CONTINUED]

(a) Pension plans [continued]

(iii) Funded status

		2014		2013
Retirement benefit asset, beginning of year	$	689	$	474
Change in retirement benefit asset		139		215
Retirement benefit asset, end of year	$	828	$	689

The assets of the Chaudiere Hydro Pension Plan are held and managed by an independent custodian and accounted for separately in the Corporation's pension funds. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investments, credit rating categories and foreign currency exposures. Based on the fair value of assets held as at December 31, 2014, CHPP's assets were comprised of 90% fixed income Canadian bonds, 6.5% Canadian and international equities and 3.5% in alternative investments. As the transfer of funds from Domtar Inc. only occurred in 2014, comparative percentages are not presented as at December 31, 2013. The last actuarial valuation with respect to this plan occurred as at November 20, 2012.

No valuation allowance has been recorded by the Corporation as at December 31, 2014 or December 31, 2013 with respect to the retirement benefit asset.

Employee future benefits under the CHPP are calculated using an annual compensation rate increase of 2.0% [2013 – 2.0%], an expected return on plan assets of 4.0% [2013 – 4.8%] and a discount rate of 4.0% [2013 – 4.8%] to calculate the liabilities.

(b) Employee future benefits other than pension plans

Employee future benefits are calculated using an annual compensation rate increase ranging from 2% to 3.1% [2013 – 2% to 3.1%] and a discount rate of 4.0% [2013 – 4.8%] to calculate the liabilities. The valuations also include several other economic and demographic assumptions including mortality rates. The mortality assumption as at December 31, 2014 has been updated resulting in an actuarial remeasurement of employee future benefits. The mortality assumption is based on the Canadian Pensioners Mortality report published by the Canadian Institute of Actuaries in February 2014.

14. EMPLOYEE FUTURE BENEFITS [CONTINUED]

(b) Employee future benefits other than pension plans [continued]

Information about the Corporation's employee future benefits other than pension plans is as follows:

	2014		
	Accumulated liability	**Expense for the year**	**Benefits paid**
Life, medical and dental insurance	**$ 5,745**	**$ 517**	**$ 464**
Retirement grant	**909**	**89**	**107**
Sick leave	**5**	**-**	**-**
	6,659	**606**	**571**
Deferred actuarial loss [Note 6]	**4,432**	**-**	**-**
	$ 11,091	**$ 606**	**$ 571**

	2013		
	Accumulated liability	Expense for the year	Benefits paid
Life, medical and dental insurance	$ 5,650	$ 564	$ 434
Retirement grant provision	927	83	21
Sick leave	5	-	-
	6,582	647	455
Deferred actuarial loss [Note 6]	3,109	-	-
	$ 9,691	$ 647	$ 455

An actuarial valuation was performed as at December 31, 2014. As a result of this exercise, the Corporation increased the accumulated liability by $1,400 [2013 – decreased by $1,761 based on an actuarial extrapolation].

The current liability portion of the accrued employee future benefits included in other accounts payable and accrued liabilities amounts to $672 [2013 – $626] and the non-current portion was $10,419 [2013 – $9,065].

15. NOTES PAYABLE

	2014	2013
Senior unsecured debentures		
Series 2005-1, 4.930%, due February 9, 2015	**$ 200,000**	$ 200,000
Series 2006-1, 4.968%, due December 19, 2036	**50,000**	50,000
Series 2013-1, 3.991%, due May 14, 2043	**150,000**	150,000
IGRS promissory note, non-interest bearing, due on demand	**2,200**	2,360
IGRS promissory note, 6.0%, due December 31, 2024	**3,295**	-
	405,495	402,360
Less current portion of IGRS notes	**(925)**	(340)
Less unamortized debt-issuance costs on debentures	**(1,362)**	(1,607)
	$ 403,208	$ 400,413

Interest payments on each of the above debentures are payable semi-annually in arrears in equal instalments. Each debenture contains customary covenants and events of default, including a covenant to ensure that the aggregate principal amount of the consolidated funded obligations does not exceed 75% of the total consolidated capitalization. Interest payments on these debentures over the next five years, including those issued subsequent to year end as described in Note 25, will be $19,198 in 2015 and $20,067 in 2016 through 2019.

The non-interest bearing IGRS promissory note was issued by PowerTrail to fund the construction of the gas collection and generation plant at the Trail Road landfill site. Pursuant to the Shareholders' Agreement dated November 3, 2005, among Energy Ottawa, IGRS and PowerTrail, the note is unsecured, non-interest bearing, subject to certain conditions and has no set terms of repayment. During the year, PowerTrail made $160 [2013 – $420] in repayments to IGRS and intends to repay an additional $740 on this note in 2015. The management of IGRS has confirmed that it does not intend to call the remaining $1,460 in 2015.

On December 31, 2014, upon adjusting its financing and capital structure, Moose Creek LP issued a new 10-year unsecured promissory note to IGRS with an interest rate of 6.0%. Quarterly repayments consisting of principal and interest are due beginning April 1, 2015 until the end of the term. Principal repayments are expected to be $185 in 2015, $260 in 2016, $275 in 2017, $292 in 2018 and $310 in 2019.

16. CAPITAL DISCLOSURES

The Corporation’s main objectives when managing capital are to:

- Ensure continued access to funding to maintain and improve the operations and infrastructure of the Corporation;
- Ensure compliance with covenants related to the credit facilities and senior unsecured debentures; and
- Align Hydro Ottawa Limited's capital structure with the debt-to-equity structure recommended by the OEB.

16. CAPITAL DISCLOSURES [CONTINUED]

The Corporation's capital consists of the following:

	2014	2013
Bank indebtedness	**$ 15,955**	$ 8,853
Notes payable [current and long-term]	**404,133**	400,753
Total debt	**420,088**	409,606
Shareholder's equity	**392,744**	381,726
Total capital	**$ 812,832**	$ 791,332
Debt capitalization ratio	**52 %**	52 %

The Corporation is in compliance with all financial covenants and limitations associated with its credit facilities and its long-term debt.

Hydro Ottawa Limited is deemed by the OEB to have a capital structure that is funded by 56% long-term debt, 4% short-term debt and 40% equity. The OEB uses this deemed structure only as a basis for setting distribution rates. As such, the Corporation's actual capital structure may differ from the OEB deemed structure.

The Corporation met its capital management objectives, which have not changed during the year.

17. SHARE CAPITAL

(a) Authorized

Unlimited number of voting first preferred shares, redeemable at one dollar per share
Unlimited number of non-voting second preferred shares, redeemable at ten dollars per share
Unlimited number of non-voting third preferred shares, redeemable at one hundred dollars per share
Unlimited number of voting fourth preferred shares [10 votes per share], redeemable at one hundred dollars per share
Unlimited number of voting Class A common shares
Unlimited number of non-voting Class B common shares
Unlimited number of non-voting Class C common shares, redeemable at the price at which such shares are issued

The above shares are without nominal or par value.

Holders of second preferred shares, fourth preferred shares and common shares are entitled to receive dividends as and when declared by the Board of Directors at their discretion.

(b) Issued

	2014	2013
214,901,003 Class A common shares	**$ 228,453**	$ 228,453

17. SHARE CAPITAL [CONTINUED]

(b) Issued [continued]

Any invitation to the public to subscribe for shares of the Corporation is prohibited by shareholder resolution.

Shareholder resolution directs the Corporation to target dividends at the greater of 60% of its annual consolidated net income or $14,000, provided that the Corporation is in compliance with the *Business Corporations Act (Ontario)* and relevant OEB guidelines, is not in breach of any covenants on its senior unsecured debentures or credit facility obligations, and does not negatively impact its credit rating as a result of the dividend payment.

On April 3, 2014, the Board of Directors declared a $19,300 dividend to the City of Ottawa, which was paid on April 10, 2014 [2013 – April 4, the Board of Directors declared an $18,600 dividend to the City of Ottawa, which was paid on April 10, 2013].

On May 1, 2008, TOHI sold the shares of both its subsidiaries creating a balance in its refundable dividend tax on hand ['RDTOH'] account. On December 5, 2013, TOHI paid an intercompany dividend to Hydro Ottawa Holding Inc. to recover its RDTOH balance which was received in 2014.

18. NON-CONTROLLING INTEREST

The non-controlling interest as at December 31, 2014 represents the sum of:

- IGRS non-controlling interest [40%] in the net assets of PowerTrail;
- IGRS and Moose Creek GP's combined non-controlling interest [49.90%] in the net assets of Moose Creek LP; and
- Hydro Québec's non-controlling interest [33.33%] in the net assets of CWPI.

During the year, Moose Creek LP issued 2,705,400 Class A units [2013 – 1,002,000 units] and 2,694,000 Class B units [2013 – 998,000 units] to its limited partners [Energy Ottawa and IGRS respectively] at a price of one dollar per unit. The current year's issuance was made with the purpose of adjusting Moose Creek LP's financing and capital structure, while the previous year's issuance was made to fund the completion of its gas collection and generation plant and to provide sufficient working capital during the initial stage of operations.

19. FINANCIAL INSTRUMENTS

(a) Carrying values

The Corporation's financial instruments consist of cash, accounts receivable, unbilled revenue, bank indebtedness, accounts payable and accrued liabilities, customer deposits and notes payable. The only financial instrument recorded at fair value is bank indebtedness and it is classified as level 1 in the pre-changeover Canadian GAAP Section 3862 fair value hierarchy. The carrying values of the Corporation's remaining financial instruments, except for notes payable, approximate fair value because of the short maturity of these instruments.

19. FINANCIAL INSTRUMENTS [CONTINUED]

(a) Carrying values [continued]

The Corporation has estimated the fair value of the senior unsecured debenture notes payable as at December 31, 2014 as amounting to $429,666 [2013 – $414,176]. The fair value has been determined based on discounting all future payments of interest and the principal repayments on February 9, 2015, December 19, 2036 and May 14, 2043 at the estimated interest rate of 3.5% [2013 – 4.0%] that would be available to the Corporation on December 31, 2014.

The Corporation cannot determine the fair value of the IGRS promissory note as the amount is non-interest bearing and has no specific repayment terms other than as agreed upon from time to time between Energy Ottawa and IGRS.

(b) Risk factors

In the normal course of business, the Corporation is exposed to market risk, credit risk and liquidity risk. The Corporation's risk exposure and strategies to mitigate these risks are noted below.

(i) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market prices are comprised of three types of risks: interest rate risk, currency risk and other price risk such as equity risk.

The Corporation is exposed to interest rate risk on its borrowings. The Corporation mitigates exposure to interest rate risk by issuing long-term fixed interest rate debt. Under the Corporation's credit facility, any advances on its operating lines expose it to fluctuations in short-term interest rates related to prime rate loans and bankers' acceptances. In addition, the fees payable on bankers' acceptances via the operating lines and capital line are based on a margin determined by reference to the Corporation's credit rating.

As at December 31, 2014, the Corporation has $37,000 [2013 – nil] of outstanding bankers' acceptances on its operating lines. Borrowing requirements on these lines are typically for a short duration as advances serve to bridge gaps between the cash outflow related to Hydro Ottawa Limited's monthly power bill and the inflows related to the settlements with customers and, as such, there is limited exposure to interest rate risk.

As at December 31, 2014, the Corporation has nil [2013 – nil] of outstanding bankers' acceptances on its capital line. Borrowing requirements on this line are typically for a short duration as advances serve to bridge gaps between the cash outflow related to significant capital acquisitions and the inflows related to the issuance of additional long-term fixed rate debt to finance such acquisitions. Consequently, there is limited exposure to interest rate risk.

19. FINANCIAL INSTRUMENTS [CONTINUED]

(b) Risk factors [continued]

(i) Market risk [continued]

As at December 31, 2014, the Corporation has limited exposure to fluctuations in foreign currency exchange rates. The Corporation does purchase a small proportion of goods and services which are denominated in foreign currencies, predominately the US dollar. The impact of the fluctuation of foreign currencies on the gains or losses of accounts payable denoted in foreign currencies is not material.

As at December 31, 2014, the Corporation has not entered into any hedging transactions or derivative contracts.

(ii) Credit risk

Credit risk is the risk that a counterparty will default on its obligations, causing a financial loss. Concentration of credit risk associated with accounts receivable and unbilled revenue is limited due to the large number of customers the Corporation services. Hydro Ottawa Limited has approximately 320,000 customers, the majority of which are residential. As a result, the Corporation did not earn a significant amount of revenue and does not have a significant receivable from any individual customer.

Hydro Ottawa Limited performs ongoing credit evaluations of its customers and requires collateral to support non-residential customer accounts receivable on specific accounts to mitigate significant losses in accordance with OEB legislation. As at December 31, 2014, the Corporation held security deposits related to power recovery and distribution sales in the amount of $14,176 [2013 – $14,514].

Energy Ottawa and its subsidiaries limit credit risk by dealing with customers that are considered to be of high credit quality.

The Corporation monitors and limits its exposure to credit risk on a continuous basis.

The carrying amount of accounts receivable and unbilled revenue is reduced by an allowance for doubtful accounts based on the credit risk applicable to particular customers and historical and other information. The Corporation records an allowance for doubtful accounts when the recoverability of an amount becomes doubtful. When the receivable amount is deemed to be uncollectible, it is written off and the allowance for doubtful accounts is adjusted accordingly. Subsequent recoveries of receivables previously provisioned or written off result in a reduction of operating costs in the consolidated statement of income, comprehensive income and retained earnings. As at December 31, 2014, the allowance for doubtful accounts was $3,828 [2013 – $1,642]. During the year, Hydro Ottawa Limited implemented a new electricity billing system. The new billing system handles write-offs in a different manner by retaining the gross receivable balance on the books for a longer period before write-off occurs. As a result, management has increased the allowance for doubtful accounts. There is no impact on net receivables and the change did not affect the Corporation's overall credit risk.

19. FINANCIAL INSTRUMENTS [CONTINUED]

(b) Risk factors [continued]

(ii) Credit risk [continued]

Credit risk associated with accounts receivable and unbilled revenue is as follows:

	2014	2013
Accounts receivable	**$ 76,067**	$ 72,262
Total unbilled revenue	**81,957**	106,757
Less allowance for doubtful accounts	**(3,828)**	(1,642)
	154,196	177,377
Of which:		
Outstanding for 30 days or less	**59,185**	64,638
Outstanding for more than 30 days but not more than 120 days	**11,836**	5,665
Outstanding for more than 120 days	**5,046**	1,959
Unbilled revenue	**81,957**	106,757
Less allowance for doubtful accounts	**(3,828)**	(1,642)
	$ 154,196	$ 177,377

As at December 31, 2014, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties and approximately 22% [2013 – 11%] of the Corporation's accounts receivable was aged more than 30 days. The Corporation's maximum exposure to credit risk is equal to the carrying value of accounts receivable and unbilled revenue less customer deposits held.

(iii) Liquidity risk

Liquidity risk is the risk that the Corporation will not meet its financial obligations as they come due. The Corporation regularly monitors and manages its liquidity risk to ensure access to sufficient funds to meet operational and capital investment requirements. The Corporation achieves this objective by ensuring that sufficient facilities, as described in Note 9, are maintained to meet obligations as they come due while minimizing standby fees and interest.

19. FINANCIAL INSTRUMENTS [CONTINUED]

(b) Risk factors [continued]

(iii) Liquidity risk [continued]

Liquidity risks associated with financial commitments are as follows:

	2014		
	Due within 1 year	Due between 1 year and 5 years	Due after 5 years
Bank indebtedness	$ 15,955	$ -	$ -
Accounts payable and accrued liabilities	175,850	-	-
Senior unsecured debentures			
Series 2005-1, 4.930%, due February 9, 2015	200,000	-	-
Series 2006-1, 4.968%, due December 19, 2036	-	-	50,000
Series 2013-1, 3.991%, due May 14, 2043	-	-	150,000
IGRS promissory note, due on demand	740	1,460	-
IGRS promissory note, 6.0%, due December 31, 2024	185	1,137	1,973
	$ 392,730	$ 2,597	$ 201,973

20. FINANCING COSTS

	2014	2013
Interest on notes payable	$ 18,621	$ 16,404
Short-term interest and fees, net of interest income	637	652
Less AFUDC	(1,857)	(2,411)
	$ 17,401	$ 14,645

21. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for PILs differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rates. A reconciliation between the statutory and effective tax rates is provided as follows:

		2014		2013
Federal and Ontario statutory income tax rate		**26.50 %**		26.50 %
Income before provision for PILs	**$**	**32,335**	$	41,958
Provision for PILs at statutory rate	**$**	**8,569**	$	11,119
Increase (decrease) resulting from:				
Permanent differences		**36**		1,093
Regulatory offset to temporary differences and changes in future tax rates		**(6,347)**		(3,001)
Future tax benefit recognized on actuarial gains recorded in OPEB deferral account		**-**		495
Prior year adjustments		**(94)**		(58)
Tax credits		**-**		(162)
Change in valuation allowance		**(48)**		42
Other		**(304)**		(118)
	$	**1,812**	$	9,410
Effective income tax rate		**5.60 %**		22.43 %

The Corporation as a rate-regulated enterprise is required to recognize future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future electricity rates.

Provision for PILs consists of the following:

		2014		2013
Current PILs corporate income tax provision	**$**	**1,469**	$	8,126
Future PILs corporate income tax provision				
Future income tax provision before regulatory adjustment		**8,984**		5,367
Regulatory adjustment for the recovery of future income tax provision		**(8,641)**		(4,083)
	$	**1,812**	$	9,410

21. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES [CONTINUED]

The Corporation's future income tax assets and liabilities are presented on the consolidated balance sheet as follows:

		2014		2013
Assets				
Future income tax assets, current	**$**	**1,015**	$	818
Future income tax assets, non-current		**11,103**		19,947
		12,118		20,765
Liabilities				
Future income tax liabilities, non-current		**(6,800)**		(6,464)
	$	**5,318**	$	14,301

Significant components of the Corporation's future income tax assets and liabilities are as follows:

		2014		2013
Property, plant and equipment and intangible assets	**$**	**(456)**	$	9,844
Employee future benefits		**3,834**		3,354
Non-capital loss carryforwards		**395**		697
Other temporary differences		**1,545**		406
	$	**5,318**	$	14,301

The Corporation's regulatory liabilities for the amounts of future income taxes expected to be refunded to customers in future electricity rates are presented on the consolidated balance sheet as follows:

		2014		2013
Regulatory liability for future income tax assets, current	**$**	**1,015**	$	818
Regulatory liability for future income tax assets, non-current		**11,055**		19,893
	$	**12,070**	$	20,711

As at December 31, 2014, the Corporation had capital losses of $700 [December 31, 2013 – $700] which have not been recognized in the consolidated financial statements.

As at December 31, 2014, Hydro Ottawa Limited and PowerTrail had corporate minimum tax credit carryforwards of $690 and $135 respectively [2013 – nil and $100 respectively] which expire between 2027 and 2034.

As at December 31, 2014, PowerTrail had non-capital tax loss carryforwards of $1,462 [2013 – $2,627] which expire between 2028 and 2030.

22. CONTINGENT LIABILITIES

Purchasers of electricity in Ontario including Hydro Ottawa Limited, through the Independent Electricity System Operator ['IESO'], are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Corporation fails to make a payment required by a default notice issued by the IESO. A prudential support obligation is calculated based upon a default protection amount and the distributor's trading limit less a reduction for the distributor's credit rating. As at December 31, 2014, the Corporation had drawn standby letters of credit in the amount of $8,150 [2013 – $16,000] against its credit facility to cover its prudential support obligation. In addition, the Corporation maintains $1,258 [2013 - $133] in other standby letters of credit to various agencies as described in Note 9 of these consolidated financial statements.

The Corporation participates with other electrical utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electrical Association Reciprocal Insurance Exchange. The Corporation is liable for additional assessments to the extent premiums collected and reserves established are not sufficient to cover the cost of claims and costs incurred. If any additional assessments were required in the future, their cost would be charged to income in the year during which they occur.

In December 2012, Hydro Ottawa Limited was charged with five charges under the Occupational Health and Safety Act with respect to an incident occurring on March 22, 2012, which resulted in the fatality of an employee of a third-party subcontractor. No charges have been or can be brought against directors, officers or employees arising from this incident. The maximum fine for each count is $500 plus a 25% Victim Fine Surcharge upon conviction. Hydro Ottawa Limited, through external counsel, is defending the charges. At this time, it is not possible to quantify the effect, if any, of these charges on these consolidated financial statements.

Various lawsuits have been filed against the Corporation for incidents that arose in the ordinary course of business. In the opinion of management, the outcomes of the lawsuits, now pending, are neither determinable nor material. Should any loss result from the resolution of these claims, such losses would be claimed through the Corporation’s insurance carrier, with any unrecoverable amounts charged to income in the year of resolution.

23. COMMITMENTS

Hydro Ottawa Limited has $58,854 in total open commitments for 2015 to 2022. This includes commitments relating to a customer information system services agreement, construction projects, spare parts and standby equipment and overhead and underground services.

Energy Ottawa plans to invest significant resources towards the Chaudiere Expansion over the next three years as described in Note 7 of these consolidated financial statements. As at December 31, 2014, Energy Ottawa has committed $20,138 in funds to commence construction.

PowerTrail is committed, under a Gas Utilization License of Occupation Agreement with the City of Ottawa, to provide a 5.5% royalty of its gross annual receipts derived from the sale of electricity associated with the use of gas from the Trail Road landfill site through 2024. In exchange, the City of Ottawa provides facilities for the collection and use of gas generated by the Trail Road landfill site.

Moose Creek LP is committed, under a Gas Utilization and Lease Agreement with a third party, to provide a royalty on its gross generation revenue ranging from 4% to 12% through 2033. These royalties are based on certain annual net generation thresholds as defined within the agreement and in 2014 were 6% [2013 – 6%]. In exchange, the third party provides the use of land for the collection and use of gas generated by the Laflèche landfill site.

23. COMMITMENTS [CONTINUED]

On June 3, 2013, Energy Ottawa renewed its lease with the National Capital Commission of Canada for an additional 20 years, through September 30, 2032. Since incorporation, the lease has granted the Corporation the right to certain lands, buildings and other generating assets at Chaudière Falls [collectively known as Generating Station No. 2]. Lease payments are determined annually, based on the minimum base rent established in 1993 of $52, plus a variable portion based on the ratio of energy generated by Generating Station No. 2 as a proportion of the Corporation's total generation production and related revenue. Energy Ottawa's estimated future payments under this lease, based on expected production and revenue, are as follows:

2015	$	128
2016		126
2017		118
2018		114
2019		114
Thereafter		1,452
	$	2,052

24. RELATED PARTY TRANSACTIONS

The following table provides the transactions entered into with related parties as well as outstanding balances at year end. These transactions occur in the normal course of business, and are transacted at the amount of consideration determined and agreed to by the related parties. Trade amounts due from and to related parties are non-interest bearing, result from normal operations and are due within one year.

24. RELATED PARTY TRANSACTIONS [CONTINUED]

	2014 Transactions during the year		2014 Balances at year end	
	Sales to related parties	**Purchases from related parties**	**Due from related parties**	**Due to related parties**
City of Ottawa and subsidiaries				
Sale of electricity [1]	**$ 44,008**	**$ -**	**$ -**	**$ -**
Commercial energy services [2]	**5,420**	**-**	**-**	**-**
Other services [2]	**7,499**	**-**	**-**	**-**
Fuel, permits and other services [3]	**-**	**918**	**-**	**-**
Property taxes [3]	**-**	**2,165**	**-**	**-**
Royalties [3]	**-**	**192**	**-**	**-**
Conservation and demand management initiatives [3]	**-**	**283**	**-**	**-**
Accounts receivable	**-**	**-**	**8,786**	**-**
Accounts payable and accrued liabilities	**-**	**-**	**-**	**107**
	$ 56,927	**$ 3,558**	**$ 8,786**	**$ 107**

	2013 Transactions during the year		2013 Balances at year end	
	Sales to related parties	Purchases from related parties	Due from related parties	Due to related parties
City of Ottawa and subsidiaries				
Electricity [1]	$ 39,908	$ -	$ -	$ -
Commercial energy services [2]	3,585	-	-	-
Other services [2]	7,684	-	-	-
Fuel, permits and other services [3]	-	1,183	-	-
Property taxes [3]	-	2,053	-	-
Royalties [3]	-	176	-	-
Conservation and demand management initiatives [3]	-	57	-	-
Accounts receivable	-	-	7,906	-
Accounts payable and accrued liabilities	-	-	-	268
Total	$ 51,177	$ 3,469	$ 7,906	$ 268

[1] Included in power recovery, distribution sales revenue and regulatory assets / liabilities
[2] Included in other revenue and contributions in aid of construction
[3] Included in operating costs

25. SUBSEQUENT EVENTS

On February 2, 2015, the Corporation successfully completed a dual tranche bond offering of senior unsecured debentures consisting of Series 2015-1, $200,000 at 2.614% due February 3, 2025 and Series 2015-2, $175,000 at 3.639% due February 2, 2045. The Corporation has used $200,000 of the $375,000 total offering to repay Series 2005-1 which became due on February 9, 2015.

On March 23, 2015, the Corporation, through its subsidiary Energy Ottawa, entered into a share and unit purchase agreement to acquire a variety of generation-related entities. The agreement includes numerous closing conditions which can have a material impact on the total purchase price. Hence, the value of the purchase commitment is not determinable at this time. The closing of this transaction is currently expected to occur in the second quarter of 2015.

26. COMPARATIVE FIGURES

In certain instances, the 2013 information presented for comparative purposes has been reclassified to conform to the consolidated financial statement presentation adopted for the current year.

Statement of Executive Compensation

The Governance and Management Resources Committee of the Board, made up entirely of independent Directors, is responsible for developing and recommending the approval of the compensation framework for the Corporation and each of its subsidiaries.

In developing the compensation framework, the Governance and Management Resources Committee is guided by two principles: the need to provide a total compensation package that will attract and retain qualified and experienced executives, and linking compensation to performance.

Executive compensation is reviewed by the Governance and Management Resources Committee and approved by the Board of Directors. In making its recommendations to the Board, the Committee examines the responsibilities and performance of individual executives, and considers the recommendations of the President and Chief Executive Officer.

In an effort to attract and retain qualified and experienced executives, the Corporation aims to offer a total compensation package that is competitive with other organizations of a similar size and scope. Executive compensation is reviewed on an annual basis and compared to market data, with the assistance of independent consultants, on an ad hoc basis to ensure competitiveness. In line with best practices for the sector, as identified by the Ontario Minister of Energy's Agency Review Panel in 2007, Hydro Ottawa applies a 50/50 weighting of market data from public and private comparators. The industry component of the market comparator group has a strong sector affiliation [e.g., Transportation and Utilities sector], and is assessed by revenue levels to ensure comparability.

Total cash compensation for Executives consists of two components*: base salary and an at risk performance incentive. Total cash compensation is benchmarked to companies of comparable size and scope in both the Ontario and national markets, with the target for total cash compensation set at the 50th percentile, or midpoint, of the market.

The at risk performance incentive component is paid on an annual basis, and is expressed as a percentage of base salary. It is designed to retain and motivate executives, to reward them for their performance during the preceding year, and to ensure alignment with shareholder objectives. Payments are based on the achievement of corporate and division objectives, both financial and non-financial, which are established each year by the Board of Directors. Non-financial targets are designed to achieve continuous improvement in relation to a number of strategic objectives including, but not limited to, customer service, operational and organizational efficiency and effectiveness, and service reliability.

Executives participate in a benefits program, which includes extended health care, dental care, basic and optional life insurance, and short-term and long-term disability insurance. This same program is available to all management group employees of the Corporation.

Executives also participate in the OMERS pension plan. This plan is a multi-employer, contributory, defined benefit pension plan established by the Province for employees of municipalities, local boards and school boards in Ontario. Pension benefits are determined by a formula based on the highest consecutive five-year average of contributory earnings and years of service. Pension benefits are indexed to increases in the Consumer Price Index subject to an annual maximum of 6 percent. Both participating employers and participating employees are required to make equal contributions to the plan based on the participating employees' contributory earnings. Earnings for pension purposes are capped based on recent plan changes.

*The total cash compensation for the President and Chief Executive Officer consists of a base salary only.

SUMMARY OF COMPENSATION

Officers of the Corporation

NAME AND PRINCIPAL POSITION[1]	YEAR	BASE SALARY ($)[2]	AT RISK PERFORMANCE INCENTIVE ($)[3]	OTHER COMPENSATION ($)[4]
Bryce Conrad President and Chief Executive Officer	2014	$363,468	N/A	$13,458
	2013	$354,579	N/A	$35,240
	2013	$344,230	N/A	$15,734
Geoff Simpson Chief Financial Officer	2014	$174,968	$42,884[6]	$8,526
	2013	$63,301[5]	N/A	$3,362
Norm Fraser Chief Operating Officer – Distribution and Customer Service	2014	$219,174	$66,121	$8,731
	2013	$216,082	$73,900	$8,894
	2012	$215,919	$67,367	$8,714
Gregory Clarke Chief Operating Officer – Generation	2014	$177,622	$53,586	$8,556
	2013	$175,116	$59,890	$8,687
	2012	$174,984	$52,535	$9,550

1 Officers whose earnings are reported are those who occupied the position at December 31, 2014

2 Amounts shown in this column have been rounded to the nearest dollar

3 Amounts shown in this column reflect the at risk performance incentive for the executive in respect of the achievement of the performance objectives for the previous financial year, paid in the reporting year

4 Amounts in this column include Board approved discretionary payments such as payments of earned and unused vacation credits, car allowance, computer allowance and employer's share of basic life insurance premiums

5 Mr. Simpson assumed the position on August 6, 2013. Had Mr. Simpson been employed in this position for the entire year, his base salary would have been $172,500

6 Given that Mr. Simpson assumed the position on August 6, 2013, the at risk performance incentive for 2013, paid in 2014, is based on both his previous position with the Corporation and the position of Chief Financial Officer

Corporate Governance

Hydro Ottawa is committed to establishing and maintaining leading governance practices for a company of its size and mandate. Because governance standards and best practices are always evolving, the company seeks to continuously improve its governance practices.

Hydro Ottawa Holding Inc. is a private, for-profit company, incorporated under the *Business Corporations Act* [Ontario]. At the same time, the company is wholly owned by the City of Ottawa and fulfills a public mandate, and is therefore mindful of its responsibility to be accountable both to its shareholder and the public. The company's governance practices are guided not simply by legal obligations, but by best business practices and standards established by independent agencies.

While Hydro Ottawa is not a reporting issuer under the Securities Act and is therefore not subject to governance standards that apply to publicly-traded companies, the company is guided by these standards and seeks to meet or exceed them. In addition, Hydro Ottawa regularly compares its governance practices to those of private and public sector organizations, and to standards set by agencies such as the Canadian Securities Administrators and the Ontario Securities Commission.

Governance Structure

Accountability for the effective oversight of the Corporation and its wholly-owned subsidiaries (Hydro Ottawa Limited and Energy Ottawa Inc.) rests with an eleven-member Board of Directors, which provides direction to the Corporation on behalf of the shareholder, the City of Ottawa. The Board provides leadership within a framework of effective controls that enables risks to be assessed and managed, and is responsible for supervising the management of the business and affairs of the Corporation and its wholly-owned subsidiaries. In carrying out its oversight function, the Board of Directors is guided by a Shareholder Declaration issued by Ottawa City Council and revised from time to time. The Corporation's Code of Business Conduct, its Director Conflict of Interest and Conduct Guidelines and a Related Party Transaction Disclosure Policy and Process also govern the actions of the Board.

In 2006, a separate Board of Directors was established to oversee the operations of Hydro Ottawa Limited, in accordance with the Affiliate Relationships Code for Electricity Distributors and Transmitters issued by the Ontario Energy Board. The powers and functions of that Board are set out in a Shareholder Declaration issued by the Hydro Ottawa Holding Inc. Board of Directors.

On a day-to-day basis, the Corporation is led by an Executive Management Team, comprising the Corporation's President and Chief Executive Officer, the Chief Financial Officer and the senior executives of the subsidiaries and critical functional areas. This team oversees the alignment of business practices and strategies with the goals of the Corporation, and drives performance by managing risks and opportunities. The Executive Management Team is accountable to the Corporation's Board of Directors through the President and Chief Executive Officer.

Key Governance Processes and Controls

Hydro Ottawa has established a number of leading governance processes and controls to assist the Board and executive management in carrying out their oversight functions.

Risk Management: An extensive, corporate-wide risk management system has been established to track indicative and predictive measures of risk. Risk assessments are included with regular reporting to the Board on all areas of the Corporation's operations.

Internal Audit: Hydro Ottawa conducts a rigorous internal audit program to verify controls and maximize business efficiency and effectiveness. A number of business processes and functions are audited annually based on an audit plan approved by the Board. The use of experienced auditors both internal and external to the Corporation ensures rigour and objectivity.

Business Continuity Plans: Plans are in place to ensure the continuance of critical operations in the event of a major emergency such as a pandemic, and to return the Corporation to normal operations as quickly as possible after such an event. They include detailed strategies for the re-assignment of resources to critical processes, and redundant supply arrangements with critical external suppliers.

Appointments to the Board of Directors

The governance structure for the Corporation [Hydro Ottawa Holding Inc.] and its wholly-owned subsidiaries [Hydro Ottawa Limited and Energy Ottawa Inc.] includes two boards of directors—the Hydro Ottawa Holding Inc. Board and the Hydro Ottawa Limited Board.

In accordance with the terms of the Shareholder Declaration, the City of Ottawa appoints all Directors to the Boards except the President and Chief Executive Officer. In doing so, the City considers candidates recommended by the Nominating Committee of the Board of Hydro Ottawa Holding Inc., but is not obliged to select these candidates. The Nominating Committee is assisted by outside consultants in its search for candidates for appointment to the Boards.

As set out in the Shareholder Declaration, all candidates for appointment to the Boards must meet certain requirements, including demonstrated integrity and high ethical standards, relevant career experience and expertise, and an understanding of the role of Hydro Ottawa both as a service to local ratepayers and an asset of taxpayers.

In addition, the nomination and selection process is designed to maintain a Board that includes the following overarching competencies among one or more directors: strong business background including competitive business experience and strategic planning; a strong financial background including financial accreditation and public or private market financing experience; industry sector experience in the areas of business of the subsidiary companies; board experience; and merger and acquisition experience.

Committees

The following committees were created to help the Boards of Directors carry out their duties. The committees meet regularly and provide feedback on their discussions to their respective Boards.

HYDRO OTTAWA HOLDING INC.

Audit: The Audit Committee reviews financial statements, accounting practices and policies, auditing processes and the results of internal and external audits and related matters. It also oversees financial risk management and assesses internal controls.

Governance and Management Resources: The Governance and Management Resources Committee reviews the Corporation's governance structures and practices to ensure that the Board of Directors can fulfill its mandate. It reviews management resources and compensation practices to ensure systems are in place to attract, retain and motivate qualified management employees. It also reviews and assesses the performance of the President and Chief Executive Officer, oversees the Board Assessment process, and monitors compliance with codes of conduct.

Investment Review: The Investment Review Committee, created by the Board of Directors effective April 2010, is responsible for assisting management and the Board of Directors in the review and pursuit of business development, acquisition and investment opportunities. In carrying out these functions, the Committee focuses on the consistency of opportunities with strategic plans and investment guidelines, the maximization of shareholder value and the management of risk.

Nominating: The Nominating Committee, with the assistance of outside consultants, identifies and evaluates potential candidates for appointment as Directors. The Nominating Committee makes recommendations to the shareholder [represented by Ottawa City Council] for the appointment of directors.

Strategic Initiatives Oversight: The Strategic Initiatives Oversight Committee, created by the Board of Directors effective November 2013, is responsible for assisting the Board of Directors in guiding management and providing support and focus for large-scale capital project efforts as identified by the Board from time to time.

Board and Committee Meeting Attendance

The following tables illustrate the attendance of members at meetings of the Boards of Directors and their committees.

HYDRO OTTAWA HOLDING INC.

DIRECTOR	BOARD MEETINGS	COMMITTEE MEETINGS
Jim Durrell (Chair)	6/6	15/15
Bryce Conrad (President and CEO)	6/6	N/A
Dale Craig	6/6	8/8
Manon Harvey*	3/3	6/6
Peter Hume	5/6	1/1
Douglas McLarty	6/6	9/9
Maria McRae	6/6	1/1
Lori O'Neill**	3/3	4/4
Ford Ralph*	3/3	8/8
Jim Watson	1/6	4/6
Ken Wigglesworth	6/6	10/10
Carole Workman***	1/2	1/1

HYDRO OTTAWA LIMITED

DIRECTOR	BOARD MEETINGS	COMMITTEE MEETINGS
Jim Durrell (Chair)	5/5	N/A
Bryce Conrad (President and CEO)	5/5	N/A
Manon Harvey	2/2	N/A
Kalai Kalaichelvan	5/5	5/5
Bob Monette	4/5	N/A
Phil Murray	5/5	4/4
Zaina Sovani	5/5	4/5

* Depicts outgoing Board members whose terms ended on June 30, 2014

** Depicts incoming Board members whose terms took effect July 1, 2014

*** Carole Workman resigned from the Board of Directors in May 2014

Members of the Boards of Directors

Hydro Ottawa Holding Inc. (HOHI)


Jim Durrell, C.M. (Chair)


Bryce Conrad


Dale Craig


Manon Harvey


Councillor Peter Hume


Douglas McLarty


Councillor Maria McRae


Lori O'Neill


Ford Ralph


Mayor Jim Watson


Ken Wigglesworth


Carole Workman

Hydro Ottawa Limited (HOL)


Jim Durrell, C.M. (Chair)


Bryce Conrad


Manon Harvey


Kalai Kalaichelvan


Councillor Bob Monette


Phil Murray


Zaina Sovani

Note: Manon Harvey was first appointed as a director of HOHI in November 2004 and previously served as a member of the Advisory Board of that corporation. She also served on the HOL Board of Directors, the Governance and Management Resources Committee, and chaired the Audit Committee until her departure in June 2014. Ford Ralph was appointed to the HOHI Board of Directors in July 2006, and also served as a member of the Audit and Investment Review Committees until his departure in June 2014. Carole Workman was appointed to the HOHI Board of Directors in 2000 and served until 2006. In 2012, she was reappointed to the HOHI Board of Directors and also served on the Governance and Management Resources Committee until her departure in April of 2014.

Terms ended November 30, 2014 for our members of Council who served on the Boards of Directors. Councillor Peter Hume served on the HOHI Board of Directors from November 2004 to November 2014 and Councillor Maria McRae and Mayor Jim Watson served from December 2010 to November 2014. Councillor Bob Monette served on the HOL Board of Directors from December 2010 to November 2014.

We wish to convey our sincere appreciation to these individuals for their dedicated service.

Lori O'Neill was appointed to the HOHI Board of Directors effective July 1, 2014

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Glossary of Terms

Electricity Industry

IESO The Independent Electricity System Operator is responsible for day-to-day operation of Ontario's electrical system. It operates the wholesale electricity market, forecasting demand and ensuring an adequate supply to meet that demand.

MDM/R The Meter Data Management and Repository system stores and manages consumption data received from Smart Meters, enabling Time-of-Use billing as part of the provincial Smart Meter Initiative.

OEB The Ontario Energy Board regulates the provincial electricity and natural gas industries in the public interest.

OPA The Ontario Power Authority is responsible for ensuring an adequate long-term supply of electricity for Ontario. It creates and implements conservation and demand management programs, ensures adequate investment in new supply infrastructure, performs long-term electricity system planning, and facilitates the development of a more sustainable and competitive electricity system. On January 1, 2015, the Ontario Power Authority [OPA] merged with the Independent Electricity System Operator [IESO] to create a new organization that will combine the OPA and IESO mandates.

Smart Meters Smart Meters measure and store data about when customers use electricity as the foundation for Time-of-Use billing.

TOU A Time-of-Use rate structure charges customers higher rates for electricity used during peak times of the day and lower rates for off-peak usage.

Internal Systems and Processes

GIS Geographic Information Systems capture, store, analyze, and display geographically referenced spatial information.

OMS The Outage Management System, when integrated with the GIS (see above) results in a single computerized map of the electricity distribution system to facilitate system planning and outage response.

SCADA Supervisory control and data acquisition refers to large-scale measurement and control systems used to monitor power generation and other distribution processes.

Financial Reporting

AcSB Accounting Standards Board is an independent body with the authority to develop and establish standards and guidance governing financial accounting and reporting in Canada.

CPA Canada Chartered Professional Accountants Canada represents the CPA profession nationally. It supports the setting of accounting, auditing and assurance standards for business, not-for-profit organizations and government, and issues guidance on control and governance.

Pre-changeover Canadian GAAP Pre-changeover Canadian Generally Accepted Accounting Principles are the common set of accounting principles, standards and procedures companies use to prepare their financial statements in Canada before the introduction of IFRS.

IFRS International Financial Reporting Standards are standards and interpretations adopted by the International Accounting Standards Board (IASB). Hydro Ottawa will be required to report under IFRS rather than pre-changeover Canadian GAAP (see above) on January 1, 2015.

Earnings

There are a number of different ways of looking at how much a company earns. The most common is "net income", but other measurements, such as EBITDA, can be useful in judging the company's ability to borrow and to expand its business.

EBITDA Earnings Before Interest, Taxes, Depreciation and Amortization is a measure of financial health that helps to show how much money a company generates to pay for its obligations (such as interest on money borrowed and taxes) and fund its future growth (through depreciation and amortization).

Net Income Net income is a company's total earnings (or profit). It is determined by subtracting expenses and losses from revenues and gains during the period.

Cash Sources and Uses

Operating Operating activities primarily measure the cash-generating abilities of Hydro Ottawa's core operations rather than its ability to raise capital or purchase assets.

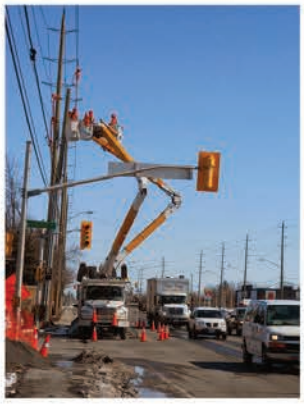
Investing Investing activities relate to Hydro Ottawa's purchases or sales of capital assets (assets that appear on the balance sheet and have a useful life of more than one year). Capital assets include property, plant and equipment, and intangible assets.

Financing Financing activities result in changes in the size and composition of the Company's equity capital and borrowings. A major source of cash from financing activities is the money received from long-term bond issuances.

Follow us @hydroottawa

Pineview, Ottawa Follow

Fearless hydro workers hanging live wires onto their new poles, all week on Innes. #amazing @hydroottawa



Caitlin Pugh @Caitie_Pugh · Oct 28

1/2 - Just had a great experience with @hydroottawa! The agent who helped me was friendly, knowledgeable, and managed my issue right away

Canadian Tire Centre Follow

Together with the Province of Ontario and @hydroottawa we are putting conservation first and having a little fun while we're at it!

Deb Beauregard Follow

.@hydroottawa Thanks for quick response to power outage Moodie/Robertson area in middle of night. Much appreciated!

Gord McFee Follow

Kudos to @hydroottawa for getting our power working after the huge disruption. I for one appreciate your Herculean efforts.

Shepherds Good Hope Following

Did you know that because of @UnitedWayOttawa and @hydroottawa we save 66% of electricity costs to run our shelter programs?!

Hansen Lawn & Garden Follow

@hydroottawa as always makes quick work of horrible situations. #withthanks

Emma Loop Follow

So @hydroottawa has cool people runnings its Twitter account.

Julie Follow

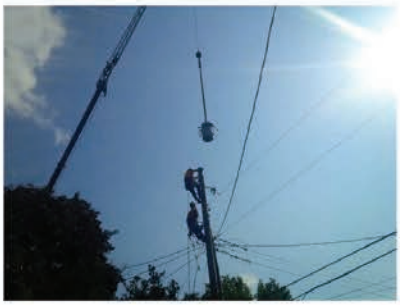
.@hydroottawa always has the kindest men working outside! (I'm sure women too).

Jim Watson Following

Great to join @hydroottawa 's Bryce Conrad and @ChiefBordeleau at Brewer Park for Christy Lake hockey game

Richard McMullen Follow

@Hydroottawa in the backyard wrapping up new pole replacement. Very impressive teamwork! They even tidy up.



Operation Come Home Following

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30% Post-Consumer Waste

TABLE OF CONTENTS - UPDATE SUBMITTED June 29, 2015

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
A Administration	4		*Attachment A-4(G)*	*2013 Reconciliation of Audited Financial Statements*
			Attachment A-4(H)	*2014 Reconciliation of Audited Financial Statements*
		3		Annual Report and Management Discussion Analysis
			Attachment A-4(C)	*2013 Annual Report of Parent Company*
			Attachment A-4(I)	*2014 Annual Report of Parent Company*
		4		Rating Agency Reports
			Attachment A-4(D)	*Ratings Report for Hydro Ottawa Holding issued by Dominion Bond Rating Service*
			Attachment A-4(E)	*Ratings Report for Hydro Ottawa Holding issued by Standard and Poors*
		5		Prospectors for Planned and Recent Share Issues
		6		Accounting Orders
		7		Accounting Standards
		8		Confirmation of Accounting Treatment for LDC owned Generation
	5	**MATERIALITY THRESHOLD**		
		1		Materiality Threshold
	6	**ADMINISTRATION**		
		1		Application and Approval Sought
		2		COS Checklist

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
A Administration	8		*Attachment A-8(E)*	*Charter of the Nominating Committee*
			Attachment A-8(F)	*Charter of the Audit Committee*
			Attachment A-8(G)	*Charter of the Governance and Management Resources Committee*
			Attachment A-8(I)	*Charter of Strategic Initiatives and Oversight Committee*
			Attachment A-8(J)	*2014 Meeting Schedule*
			Attachment A-8(K)	*Director Orientation and Continuity Education Policy and Process*
			Attachment A-8(L)	*Code of Business Conduct*
			Attachment A-8(M)	*Director Conflict of Interest and Conduct Guidelines*
			Attachment A-8(N)	*Related Party Transactions Disclosure Policy and Process*
			Attachment A-8(O)	*Business Conduct Hotline Brochure*

B - Rate Base

1 RATE BASE OVERVIEW

	1		Rate Base
	2		HOL Distribution System Plan
		Attachment B-1(A)	*Material Investments*
		Attachment B-1(B)	*2014 Annual Planning Report*
		Attachment B-1(C)	*Grid Transformation Plan*

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
B Rate Base	1		*Attachment B-1(D)*	*3rd Party Review Kinetrics Review Letter*
		3		Information Technology Strategy
			Attachment B-1(E)	*IT Strategy*
		4		CIS Transition Project
	2	**GROSS ASSETS**		
		1		Assets – Property Plant and Equipment Continuity Schedule
			Appendix 2-BA	*Fixed Asset Continuity Schedule*
	3	**ALLOWANCE FOR WORKING CAPITAL**		
		1		Working Capital Requirement
			Attachment B-3(A)	*Cost of Power 2016 to 2020*
	4	**SMART METER STRANDED ASSETS**		
		1		2016 Proposed treatment for Recovery of Stranded Meters
			Appendix 2-S	*Stranded Meter Treatment*
	5	**CAPITAL EXPENDITURES**		
		1		Capital Expenditure Overview
			Appendix 2-AA	*Capital Projects Table*
			Appendix 2-AB	*Capital Expenditure Summary*

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
B Rate Base	5	2		Capitalization Policy
			Attachment B-5(A)	*Capitalization Policy*
		3		Capitalization of Overhead
			Appendix 2-D	*Overhead Expenses*
		4		Service Quality and Reliability Performance
			Appendix 2-G	*Service Reliability Indicators*

C - Operating Revenue

1 LOAD AND REVENUE FORECASTS

	1		Load Forecast
		Appendix 2-I	*Load Forecast CDM Adjustment Work Form*
		Attachment C-1(A)	*ITRON 2014 Hydro Ottawa Long-Term Electric Energy and Demand Forecast*
	2		Accuracy of Load Forecast and Variance Analyses
		Appendix 2-IA	*Summary and Variance of Actual and Forecast Data*
		Attachment C-1(B)	*Weather Normalized Comparison*

2 OTHER REVENUE

	1		Other Revenue Summary
		Appendix 2-H	*Other Operating Revenue*

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
C Operating Revenue		2		Service Charges

D - Operating Expenses

1 OPERATING EXPENSES OVERVIEW

		1		Operating Expenses Summary
		2		Operating Maintenance and Administration Overview
			Appendix 2-JA	*Summary of Recoverable OM&A Expenses*
			Appendix 2-L	*Recoverable OM&A Cost per Customer and per Full Time Equivalent*
			Attachment D-1(A)	*Budget Memo*
		3		OM&A Cost Drivers and Program Variance Analysis
			Appendix 2-JB	*OM&A Cost Drivers*
			Appendix 2-JC	*OM&A Programs Table*
			Attachment D-1(E)	*OM&A Programs*
		4		Historical and Forward Looking Productivity Initiatives
			Attachment D-1(C)	*Productivity Scorecard Q4 2014*
		5		Productivity & Benchmarking Overview
			Attachment D-1(D)	*PSE Benchmarking Report*
		6		Customer Service Strategy

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
D Operating Expenses	1		*Attachment D-1(F)*	*Customer Persona*
		7		Workforce Planning Strategy
		8		Employee Compensation Strategy 2016
			Appendix 2-K	*Employee Costs*
			Attachment D-1(B)	*Actuarial Report*
		9		Health, Safety and Environment
		10		Conservation and Demand Management Plan 2015-2020
			Attachment D-1(G)	CDM Plan – Hydro Ottawa – Renfrew Hydro
	2	**PROGRAM DELIVERY COSTS**		
		1		Shared Services and Corporate Cost Allocation
			Appendix 2-N	*Shared Services and Corporate Cost Allocation*
		2		Purchases of Non-Affiliate Services
			Attachment D-2(A)	*Procurement Policy*
			Attachment D-2(B)	*Procurement and Disbursements Policy*
			Attachment D-2(C)	*Procurement Process*
		3		One-Time Costs
		4		Regulatory Costs

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
D Operating Expenses	2		*Appendix 2-M*	*Regulatory Costs*
		5		Low-Income Energy Assistance Program
		6		Charitable and Political Donations
		7		Non-Recoverable Contributions
	3	**DEPRECIATION, AMORTIZATION AND DEPLETION**		
		1		Depreciation, Amortization Disposal
	4	**TAXES OR PAYMENTS IN LIEU OF TAXES**		
		1		Taxes or Payments in Lieu of Taxes
			Attachment D-4(A)	*HOL 2012 Tax Return Redacted*
			Attachment D-4(B)	*HOL 2013 Tax Return Redacted*
			Attachment D-4(C)	*PILS Workform 2016*
			Attachment D-4(D)	*PILS Workform 2017*
			Attachment D-4(E)	*PILS Workform 2018*
			Attachment D-4(F)	*PILS Workform 2019*
			Attachment D-4(G)	*PILS Workform 2020*
	5	**CONSERVATION AND DEMAND MANAGEMENT**		
		1		Lost Revenue Adjustment Mechanism

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
D Operating Expenses	5		*Attachment D-5(A)*	*OPA Final Verified Annual 2013 CDM Report*
			Attachment D-5(B)	*OEB 2013 CDM Annual Report*
		2		LRAM Variance Account

E - Cost of Capital and Capital Structure

1 COST OF CAPITAL AND CAPITAL STRUCTURE

		1		Cost of Capital and Capital Structure
			Appendix 2-OA	*Capital Structure*
			Appendix 2-OB	*Debt Instruments*
			Attachment E-1(A)	*Credit Agreement as Amended*
			Attachment E-1(B)	*Grid Promissory Note*
			Attachment E-1(C)	*HOL $50 million Promissory Note*
			Attachment E-1(D)	*HOL $107.185 million Promissory Note*
			Attachment E-1(E)	*HOL $138.667 million Promissory Note*
			Attachment E-1(F)	*HOL $121.333 million Promissory Note*

F - Calculation of Revenue Deficiency or Surplus

1 CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
F - Calculation of Revenue Deficiency or Surplus	1	1		Calculation or Revenue Deficiency or Sufficiency
			Attachment F-1(A)	*Revenue Requirement Workform 2016*
			Attachment F-1(B)	*Revenue Requirement Workform 2017*
			Attachment F-1(C)	*Revenue Requirement Workform 2018*
			Attachment F-1(D)	*Revenue Requirement Workform 2019*
			Attachment F-1(E)	*Revenue Requirement Workform 2020*

G - Cost Allocation

1 COST ALLOCATION STUDY REQUIREMENTS

	1		Cost Allocation
		Appendix 2-P	*Cost Allocation*
		Attachment G-1(A)	*Hydro Ottawa Cost Allocation Report*
		Attachment G-1(B)	*Hydro Ottawa 2016 Cost Allocation Model*
		Attachment G-1(C)	*Hydro Ottawa 2017 Cost Allocation Model*
		Attachment G-1(D)	*Hydro Ottawa 2018 Cost Allocation Model*
		Attachment G-1(E)	*Hydro Ottawa 2019 Cost Allocation Mode*
		Attachment G-1(F)	*Hydro Ottawa 2020 Cost Allocation Mode*
	2		Unmetered Loads

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents

H - Rate Design

1 FIXED/VARIABLE PROPORTION

1 — Fixed / Variable Proportion

2 POLICY CONSULTATION

1 — Rate Design Policy Consultation

3 RETAIL TRANSMISSION SERVICE RATES

1 — Retail Transmission Service Rates

Attachment H-3(A) — *2015 RTSR Model*

4 RETAIL SERVICE CHARGES

1 — Retail Service Charges

5 WHOLESALE MARKET SERVICE RATE

1 — Wholesale Market Service Rate

6 SMART METERING CHARGE

1 — Smart Metering Charge

7 SPECIFIC SERVICE CHARGES

1 — Specific Service Charges

Attachment H-7(A) — *Service Charge Calculations – Proposed and New*

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
H Rate Design	**8**	**LOW VOLTAGE SERVICE RATES**		
		1		Low Voltage Service Rates
	9	**LOSS ADJUSTMENT FACTORS**		
		1		Lost Adjustment Factors
			Appendix 2-R	*Loss Factor*
	10	**TARIFF OF RATES AND CHARGES**		
		1		Current and Proposed Tariff of Rates and Charges
			Appendix 2-Z	*Proposed Tariff of Rates and Charges*
			Attachment H-10(A)	*January 1, 2015 Hydro Ottawa Limited Tariff of Rates and Charges*
	11	**REVENUE RECONCILIATION**		
		1		Revenue per Rate Class under Current and Proposed Rates
			Appendix 2-V	*Revenue Reconciliation*
	12	**BILL IMPACT INFORMATION**		
		1		Bill Impact Information
			Appendix 2-W	*Bill Impacts*

I - Deferral and Variance Accounts

	1	**STATUS OF DEFERRAL AND VARIANCE ACCOUNTS**		

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
I Deferral and Variance Accounts		1		Current Deferral and Variance Accounts
		2		New Deferral and Variance Accounts
	2	**PILS AND TAX VARIANCE: ACCOUNT 1592**		
		1		Account 1592 PILs and Tax Variance
	3	**HARMONIZED SALES TAX DEFERRAL ACCOUNT**		
		1		Harmonized Sales Tax Deferral Account
			Appendix 2-TB	Account 1592
	4	**ONE-TIME INCREMENTAL IFRS COST**		
		1		One-Time Incremental IFRS Cost
			Appendix 2-U	*IFRS Transition Costs*
	5	**ACCOUNT 1575**		
		1		Breakdown of Balance related to IRFS-CGAAP
	6	**ACCOUNT 1576**		
		1		Accounting Changes under CGAAP
	7	**RETAIL SERVICE CHARGES**		
		1		Retail Service Charges
	8	**DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS**		

Exhibit	Tab	Schedule	Appendix/ Attachment	Contents
I Deferral and Variance Accounts	8	1		Disposition of Deferral and Variance Accounts
			Attachment I-8(A)	*EDDVAR Continuity Schedule*

RATE BASE

1.0 INTRODUCTION

This Schedule provides an overview of Hydro Ottawa Limited's ("Hydro Ottawa") distribution rate base and a discussion of year over year variances.

In accordance with the Ontario Energy Board's ("the Board") Update to Chapter 2 of the Filing Requirements For Electricity Distribution Rate Applications, issued July 18, 2014, the rate base used to determine the revenue requirement for the Test Years include a forecast of net fixed assets, calculated on a mid-year average basis, plus working capital allowance ("WCA"). Net fixed assets are gross assets in service minus accumulated amortization and contributed capital.

Table 1 shows Hydro Ottawa's rate base values for historical years (2012 Approved, 2012, ~~and~~ 2013 and 2014 Actual, 2014 forecast), bridge year 2015 and test years 2016 through 2020 Budget. Table 1 provides the opening, closing and average balances for gross assets and accumulated depreciation. Table 1 further provides the closing balance for net fixed assets and Hydro Ottawa's working capital allowance.

Table 2 shows the following variances:

- Historical Board-approved (2012) vs. Historical Actual (2012);
- Historical Actual (2013) vs. preceding Historical Actual (2012);
- Forecast (2014) vs. preceding Historical Actual (2013);
- Historical Actual (2014) vs. preceding Historical Actual (2013);
- Bridge (2015) vs. Forecast (2014)
- Test Year (2016) vs. Bridge (2015); and
- Test Years (2017 to 2020) vs. preceding Test Years (2016 to 2019)

Table 1 – Summary of Rate Base (000)

	2012 Approved	2012 Actual	2013 Actual	2014 Forecast	2014 Actual	2015[1] Bridge Year	2016[1] Test Year	2017[1] Test Year	2018[1] Test Year	2019[1] Test Year	2020[1] Test Year
Opening Gross Assets	586,645	571,283	626,263	616,643[2]	616,643	728,873	834,010	920,628	1,005,754	1,098,217	1,165,068
Closing Gross Assets	653,691	626,263	730,170	728,873	721,226	834,010	920,628	1,005,754	1,098,217	1,165,068	1,276,967
Average Gross Assets	620,168	598,773	678,217	672,758	668,935	781,441	877,319	963,191	1,051,986	1,131,643	1,221,018
Opening Accumulated Depreciation	$39,178	$36,818	$75,370	$0[3]	$0	$35,919	$73,464	$113,277	$156,409	$202,443	$250,379
Closing Accumulated Depreciation	$78,417	$75,370	$114,030	$35,919	$33,361	$73,464	$113,277	$156,409	$202,443	$250,379	$299,661
Average Accumulated Depreciation	$58,798	$56,094	$94,700	$17,960	$16,680	$54,692	$93,371	$134,843	$179,426	$226,411	$275,020
Average Net Fixed Assets Closing	561,371	542,679	583,517	654,798	652,254	726,750	783,948	828,348	872,559	905,231	945,998
Working Capital Allowance	107,692	111,188	119,825	119,859	124,986	132,740	139,358	142,234	147,738	145,493	148,273
Rate Base	**669,062**	**653,867**	**703,342**	**774,657**	**777,240**	**859,490**	**923,306**	**970,582**	**1,020,297**	**1,050,724**	**1,094,270**

[1] 2015 to 2020 Balances reflect 2014 Forecast. Numbers in table were incorporated into proposed rates for 2016 to 2020. Rates for 2016 to 2020 will be updated once the OEB releases the 2016 models.

[2] Includes one-time adjustment of a decrease to opening Gross Asset values of $114,030k as well as an adjustment of $502k for IFRS financial reporting as described in B-2-1

[3] Includes one-time adjustment of a decrease to opening Accumulated Depreciation values of $114,030k for IFRS financial reporting as described in B-2-1

Table 2 – Rate Base Variances (000)

	2012 Board Approved Vs Actual	2013 Vs 2012	2014 Forecast Vs 2013	2014 Actual Vs 2013	2015[4] Vs 2014 Forecast	2016[4] Vs 2015[4]	2017[4] Vs 2016[4]	2018[4] Vs 2017[4]	2019[4] Vs 2018[4]	2020[4] Vs 2019[4]
Opening Gross Assets	15,362	54,980	(9,621)[5]	(9,621)[3]	112,230	105,137	86,618	85,126	92,463	66,851
Closing Gross Assets	27,428	103,907	(1,297)	(8,944)	105,137	86,618	85,126	92,463	66,851	111,899
Average Gross Assets	21,395	79,443	(5,459)	(9,282)	108,684	95,878	85,872	88,795	79,657	89,375
E										
Opening Accumulated Depreciation	2,360	38,551	(75,370)[6]	(75,370)[4]	35,919	37,545	39,813	43,132	46,034	47,936
Closing Accumulated Depreciation	3,047	38,660	(78,110)[7]	(80,669)[5]	37,545	39,813	43,132	46,034	47,936	49,282
Average Accumulated Depreciation	2,704	38,606	(76,740)	(78,019)	36,732	38,679	41,473	44,583	46,985	48,609
Average Net Fixed Assets	18,691	40,838	71,281[8]	68,737[6]	71,952	57,199	44,400	44,211	32,672	40,766
Working Capital Allowance	(3,496)	8,637	35	5,161	12,881	6,617	2,876	5,504	(2,245)	2,780
Rate Base Change	**15,195**	**49,475**	**71,316**	**73,898**	**84,833**	**63,816**	**47,276**	**49,716**	**30,427**	**43,546**

[4] 2015 to 2020 Balances reflect 2014 Forecast. Numbers in table were incorporated into proposed rates for 2016 to 2020. Rates for 2016 to 2020 will be updated once the OEB releases the 2016 models.
[5] Includes one-time adjustment to opening Gross Asset values of $114,030k
[6] Includes one-time adjustment to opening Gross Asset values of $114,030k
[7] Includes one-time adjustment to opening Gross Asset values of $114,030k
[8] 2014 opening Net Fixed Asset balance includes a one-time adjustment $502k, please see Exhibit B-2-1

2.0 2012 ACTUAL RATE BASE VERSUS 2012 APPROVED

Hydro Ottawa's approved 2012 rate base was $15.2M higher than actual rate base

- Average assets were $18.7M lower in 2012 actual
  - Additional $16.4M in net assets, $11.4M less than Board approved
  - $27.1M more actual construction in progress ("CIP") than forecasted
- $3.5M more was required in WCA in 2012 actual over approved

3.0 2013 ACTUAL VERSUS 2012 ACTUAL

Hydro Ottawa's actual 2013 rate base was $49.5M higher than 2012 actual

- Average assets were $40.8M higher in 2013
  - $65.2M additions in 2013, $48.8M higher than 2012
  - $2.8M in net deletions, $3M higher than 2012
- $8.6 more was required in WCA over 2012

4.0 2014 FORECAST VERSUS 2013 ACTUAL

Hydro Ottawa's forecasted 2014 rate base was $71.3M higher than 2013 actual.

- Average assets are forecasted to be $71.3M higher
  - $76.3M additions are forecasted in 2014[9], $11.1M higher than 2013
  - $1.1M in net deletions, $1.7M less than 2013
  - $6.1M less is forecasted to be in CIP at the end of 2014
- WCA is forecasted to stay relatively flat

[9] Excluding one-time adjustment to 2014 opening net fixed assets

2014 ACTUAL VERSUS 2013 ACTUAL

Hydro Ottawa's actual 2014 rate base was $73.9M higher than 2013 actual.

- Average assets were $68.7M higher in 2014
  - $71.2M additions in 2014[10], $6.0M higher than 2013
  - $2.7M in net deletions, $0.1M less than 2013
  - $4.3M less in CIP at the end of 2014
- $5.1 more was required in WCA over 2013

5.0 2015 BRIDGE VERSUS 2014 FORECAST

Hydro Ottawa's 2015 Bridge Year rate base is budgeted to be $84.8M higher than 2014 forecast.

- Average assets are budgeted to be $72.0M higher
  - $67.6M additions are budgeted in 2015, $8.7M less than 2014,
  - $18.2M less is budgeted to be in CIP at the end of 2015
- WCA is budgeted to be $12.9M more than required 2014 forecast

6.0 2016 TEST YEAR VERSUS 2015 BRIDGE YEAR

Hydro Ottawa's 2016 Test Year rate base is budgeted to be $63.8M higher than budgeted for the 2015 Bridge Year.

- Average assets are budgeted to be to be $57.2M higher
  - $46.8M additions planned in 2016, $20.8M less than 2015
  - $8.2M more is budgeted to be in CIP at the end of 2016
- WCA is budgeted to be $6.6M more than required 2015

[10] Excluding one-time adjustment to 2014 opening net fixed assets

7.0 2017 TEST YEAR VERSUS 2016 TEST YEAR

Hydro Ottawa's 2017 Test Year rate base is budgeted to be $47.3M higher than the 2016 Test Year.

- Average Assets are budgeted to be to be $44.4M higher
  - $42M additions planned for 2017, $4.8M less than 2016
  - $4.1M more is budgeted to be in construction in progress at the end of 2017
- WCA is budgeted to be $2.9M more than required in 2016

8.0 2018 TEST YEAR VERSUS 2017 TEST YEAR

Hydro Ottawa's 2018 Test Year rate base is budgeted to be $49.7M higher than 2017 Test Year.

- Average Assets are budgeted to be to be $44.2M higher
  - $46.4M additions planned for 2018, $4.4M more than 2017
  - $4.1M less is budgeted to be in CIP at the end of 2018
- WCA is budgeted to be $5.5M more than required in 2017

9.0 2019 TEST YEAR VERSUS 2018 TEST YEAR

Hydro Ottawa's 2019 Test Year rate base is budgeted to be $30.4M higher than the 2018 Test Year.

- Average Assets are budgeted to be to be $32.7M higher
  - $18.9M additions planned for 2019, $27.5M less than 2018
  - $29.0M more is budgeted to be in CIP at the end of 2019
- WCA is budgeted to be $2.2M less than required in 2018

10.0 2020 TEST YEAR VERSUS 2019 TEST YEAR

Hydro Ottawa's 2020 Test Year rate base is budgeted to be $43.5M higher than the 2019 Test Year.

- Average Net Assets are budgeted to be to be $40.8M higher
    - $62.6M additions planned in 2020, $43.7M more than 2019
    - $18M less is budgeted to be in CIP at the end of 2020
- WCA is budgeted to be $2.8M more than required in 2019

For more details on Capital Additions see Exhibit B-2-1 (Updated). In addition, for more details related to the Allowance for Working Capital see Exhibit B-3-1 (Updated).


HydroOttawa
Distribution System Plan
2016
HydroOttawa
SAFETY FIRST

Table of Contents

List of Figures

List of Tables

Glossary

AIP	Asset Investment Planning
AMP	Asset Management Process
AMPR	Asset Management Planning Report
APR	Annual Planning Report
BDC	Builder Developer Council
CAIDI	Customer Average Interruption Duration Index
CCRA	Connection & Cost Recovery Agreement
CDP	Community Design Plan
CEA	Canadian Electrical Association
CEATI	Centre for Energy Advancement through Technological Innovation
CGA	Common Ground Alliance
Chapter 5	Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements, March 28, 2013
CIA	Connection Impact Assessment
CSA	Canadian Standard Association
DC	Direct Current
DER	Distributed Energy Resources
DGA	Dissolved Gas Analysis
DS	Distribution Station
DSC	Distribution System Code
DSP	Distribution System Plan
ECA	Electrical Contractors Association
EDA	Electricity Distributors Association
ESA	Electrical Safety Authority
FEMI	Feeders Experiencing Multiple Interruptions
FIT	Feed-In-Tariff
FSM	Field Service Management

GEA	Green Energy Act
GIS	Geographic Information System
GOHBA	Greater Ottawa Home Builders Association
GTAP	Grid Transformation Action Plan
HCI	Hydroelectric Contract Initiative
HESOP	Hydroelectric Standard Offer Program
HOL	Hydro Ottawa Limited
HONI	Hydro One Networks Inc.
HVDS	High Voltage Distribution Station
Hydro One	Hydro One Networks Inc.
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
IR	Infrared
IRRP	Integrated Regional Resource Planning
ITIC	Information Technology Industry Council
KPI	Key Performance Indicator
LDC	Local Distribution Company
LoS	Loss of Supply
LRT	Light Rail Transit
LTR	Limited Time Rating
NRC	National Research Council of Canada
O&M	Operation & Maintenance
O/H	Overhead
OEB	Ontario Energy Board
OLRT	Ottawa Light Rail Transit
OM&A	Operation, Maintenance & Administration
OMS	Outage Management System
OPA	Ontario Power Authority
ORCGA	Ontario Regional Common Ground Alliance
ORTAC	Ontario Resource and Transmission Assessment Criteria

PCB	Polychlorinated Biphenyl
PILC	Paper Insulated Lead Cable
PMBOK	Project Management Body of Knowledge
PSUI-CDM	Process and Systems Upgrade initiative - Conservation Demand Management
REG	Renewable Energy Generation
RESOP	Renewable Energy Standard Offer Program
RFP	Request for Proposal
RIP	Regional Infrastructure Planning
RTU	Remote Terminal Units
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SARFI	System Average Root Mean Square (RMS) Variation Frequency Index
SCADA	Supervisory Control And Data Acquisition
SF6	Sulfur Hexafluoride
SLA	Service Level Agreement
the Board	Ontario Energy Board
the City	City of Ottawa
TIM	Testing, Inspection & Maintenance
TOD	Transit Oriented Developments
TS	Transmission Station
U/G	Underground
UCC	Utility Coordinating Committee
XFMR	Transformer
XLPE	Cross-Linked Polyethylene

1

1 Definitions

10 day Limited Time Rating (LTR)	the maximum loading level that can be applied to a station power transformer over a 10 day period resulting in a 0.1% loss in transformer life
Asset Management Planning Report	part of the Annual Planning Report (see Attachment B-1(B)) where asset management practices used by HOL are documented
Budget Program	A grouping of similar projects that address the same assets and primary drivers.
Capital Program	A grouping of Budget Programs that have a similar asset type which are grouped on a meaningful basis for management reporting and are associated with the OEB Investment Categories.
Cold Load Pick Up	the operation of restoring power to equipment that has been without power for a period of time and thus will require additional current for the equipment restart
Corrective Maintenance	activities aimed at fixing discovered issues of an asset
Distribution Assets	all infrastructure and equipment owned by HOL outside of the substation used to distribute power to customers
Distribution Station (DS)	A sub-transmission (44kV or 13.2kV) connected substation that steps down voltage to a distribution level (<44kV)
High Voltage Distribution Station (HVDS)	a transmission (≥50kV) connected substation that steps down voltage to a distribution or sub-transmission level (<50kV)
Key Performance Indicator	a measure of continuous improvement in asset management planning, capital investment planning and in customer oriented performance
LEAN	a continuous improvement program focused on eliminating waste from business processes
Maintenance Program	a set of planned activities which improve the condition of HOL's assets
Measures	a quantifiable unit used to identify KPIs
Overhead	all infrastructure and equipment used to distribute power to customers

	that is supported above ground level by a series of poles
Predictive Maintenance	activities that are used to determine the condition of an asset in order to predict when maintenance or replacement should be performed
Preventative Maintenance	activities that are regularly performed on equipment to lessen the likelihood of it failing
Program	an activity plan that includes multiple subprojects
Project	a specific plan carried out to address a need
Station Assets	all infrastructure and equipment owned by HOL inside the substation yard used to convert transmission voltages to distribution voltages
System Distribution Assets	all distribution and station assets owned by HOL used to convert transmission voltages to distribution voltages and distribute power to customers
Transmission Station (TS)	a transmission (≥50kV) connected substation that steps down voltage to a lower transmission voltage (≥50kV)
Underground	all infrastructure and equipment used to distribute power to customers that is located beneath ground level

1

HOL Substation Table

The following HOL and HONI owned stations in the table below are used to supply HOL's customers. The stations are herein referenced by the nomenclature (HOL Station Name) used by HOL.

HOL Station Name	Designation	Owner	Primary/Secondary Voltage (kV)
Albion TA	HVDS	HONI-HOL	230/13.2
Albion UA	DS	HOL	13.2/4.16
Alexander DS	DS	HONI	44/27.6
Augusta UD	DS	HOL	13.2/4.16
Bantree AL	DS	HOL	13.2/4.16
Barrhaven DS	DS	HOL	44/8.32
Bayshore DS	DS	HOL	44/8.32
Bayswater UJ	DS	HOL	13.2/4.16
Beaconhill MS	DS	HOL	44/8.32
Beaverbrook	DS	HOL	44/12.43
Beckwith DS	DS	HONI	44/27.6
Beechwood UB	DS	HOL	13.2/4.16
Bells Corner DS	DS	HOL	44/8.32
Bilberry TS	HVDS	HONI	115/27.6
Blackburn MS	DS	HOL	44/8.32
Borden Farm DS	DS	HOL	44/8.32
Bridlewood MS	HVDS DS HVDS DS	HOL	115/27.6 44/27.6 115/8.32 44/8.32
Bronson SB	DS	HOL	13.2/4.16
Brookfield AF	DS	HOL	13.2/4.16
Cahill AN	DS	HOL	13.2/4.16

Cambridge AM	DS	HOL	13.2/4.16
Carling SM	DS	HOL	13.2/4.16
Carling TM	HVDS	HONI-HOL	115/13.2
Casselman MS	DS	HOL	44/8.32
Centrepointe DS	HVDS	HOL	115/8.32
Church AA	DS	HOL	13.2/4.16
Clifton UL	DS	HOL	13.2/4.16
Clyde UC	DS	HOL	13.2/4.16
Cyrville MTS	HVDS	HOL	115/27.6
Dagmar AC	DS	HOL	13.2/4.16
Eastview UT	DS	HOL	13.2/4.16
Edwin UV	DS	HOL	13.2/4.16
Ellwood MTS	HVDS	HOL	230/13.2
Epworth DS	HVDS	HOL	115/8.32
Fallowfield MS	HVDS	HOL	115/27.6
Fisher AK	DS	HOL	13.2/4.16
Florence UF	DS	HOL	13.2/4.16
Gladstone UX	DS	HOL	13.2/4.16
Hawthorne TS	HVDS	HONI	230/44
Henderson UN	DS	HOL	13.2/4.16
Hillcrest AH	DS	HOL	13.2/4.16
Hinchey TH	HVDS	HONI-HOL	115/13.2
Holland SH	DS	HOL	13.2/4.16
Janet King DS	DS DS	HOL	44/27.6 44/8.32
Jockvale DS	DS	HOL	44/8.32
Kanata MTS	HVDS	HOL	230/27.6
King Edward SK	DS	HOL	13.2/4.16
King Edward TK	HVDS	HONI-HOL	115/13.2
Langs AP	DS	HOL	13.2/4.16

Leitrim MS	DS	HOL	44/27.6
Limebank MS	HVDS	HOL	115/27.6
Lincoln Heights TD	HVDS	HONI-HOL	115/13.2
Lisgar TL	HVDS	HONI-HOL	115/13.2
Longfields DS	DS	HOL	44/27.6
Manordale DS	HVDS	HOL	115/8.32
Manotick DS	HVDS	HONI	115/8.32
Marchwood MS	HVDS	HOL	115/27.6
McCarthy AQ	DS	HOL	13.2/4.16
Merivale DS	HVDS	HOL	115/8.32
Moulton MS	HVDS	HOL	115/27.6
Munster DS	DS	HOL	44/8.32
Nepean AB	DS	HOL	13.2/4.16
Nepean TS	HVDS	HONI	230/44
Overbrook SO	DS	HOL	13.2/4.16
Overbrook TO	HVDS	HONI-HOL	115/13.2
Parkwood Hills DS	DS	HOL	44/8.32
Playfair AJ	DS	HOL	13.2/4.16
Q.C.H. DS	DS	HOL	44/8.32
Queens UQ	DS	HOL	13.2/4.16
Richmond North DS	DS	HOL	44/8.32
Richmond South DS	HVDS	HOL	115/8.32
Rideau Heights DS	DS	HOL	44/8.32
Riverdale SR	DS	HOL	13.2/4.16
Riverdale TR	HVDS	HONI-HOL	115/13.2
Russell TB	HVDS	HONI-HOL	115/13.2
Shillington AD	DS	HOL	13.2/4.16
Slater SA	DS	HOL	13.2/4.16
Slater TS	HVDS	HONI-HOL	115/13.2
South Gloucester DS	HVDS	HONI	115/8.32

South March TS	HVDS	HONI	230/44
South March DS	DS	HOL	44/12.43
Stafford Road DS	DS	HOL	44/8.32
Startop MS	DS	HOL	44/8.32
Terry Fox MTS	HVDS	HOL	230/27.6
Uplands MS	HVDS	HOL	115/27.6
Urbandale AE	DS	HOL	13.2/4.16
Vaughan UG	DS	HOL	13.2/4.16
Walkley UZ	DS	HOL	13.2/4.16
Woodroffe DS	DS	HOL	44/8.32
Woodroffe TW	HVDS	HONI-HOL	115/13.2
Woodroffe UW	DS	HOL	13.2/4.16

1

1 Distribution System Plan

Hydro Ottawa Limited's (HOL) Distribution System Plan (DSP) has been put together in line with the Ontario Energy Board's Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements (Chapter 5).

1.0 HOL DSP

Table 1.0.1 shows the mapping of the sections within HOL's DSP to those identified in Chapter 5.

Table 1.0.1 - DSP Section Mapping

HOL DSP Section		Chapter 5 Section	
1	**Distribution System Plan**	**5.2**	**Distribution System Plans**
1.0	**HOL DSP**	**5.2**	**Distribution System Plans**
1.0.1	Corporate Strategic Direction & Asset Management Objectives	5.2	Distribution System Plans
1.1	**Distribution System Plan Overview**	**5.2.1**	**Distribution System Plan overview**
1.1.1	Key Elements of the DSP	5.2.1 a)	
1.1.2	Sources of Cost Savings	5.2.1 b)	
1.1.3	DSP Period	5.2.1 c)	
1.1.4	Vintage of Information	5.2.1 d)	
1.1.5	Asset Management Process Updates	5.2.1 e)	
1.1.6	Aspects Contingent on Ongoing Activities or Future Events	5.2.1 f)	
1.2	**Coordinated Planning with Third Parties**	**5.2.2**	**Coordinated planning with third parties**
1.2.1	Consultations	5.2.2 a)	
1.2.2	Deliverables	5.2.2 b)	
1.2.3	IESO Letter of Comment – HOL's REG Investments Plan	5.2.2 c)	

1.3	**Performance Measurement for Continuous Improvement**	**5.2.3**	**Performance measurement for continuous improvement**
1.3.1	Distribution System Planning Process Performance Indicators	5.2.3 a)	
1.3.2	Performance Summary	5.2.3 b)	
1.3.3	Effect of Performance Indicators on the DSP	5.2.3 c)	
2	**Asset Management Process**	**5.3**	**Asset Management Process**
2.1	**Asset Management Process Overview**	**5.3.1**	**Asset management process overview**
2.1.1	Asset Management Objectives	5.3.1 a)	
2.1.2	Asset Management Process Components	5.3.1 b)	
2.2	**Overview of Assets Managed**	**5.3.2**	**Overview of assets managed**
2.2.1	Features of the Distribution Service Area	5.3.2 a)	
2.2.2	System Configuration	5.3.2 b)	
2.2.3	Asset Demographics and Condition	5.3.2 c)	
2.2.4	Capacity of the Existing System Assets	5.3.2 d)	
2.3	**Asset Lifecycle Optimization Policies and Practices**	**5.3.3**	**Asset lifecycle optimization policies and practices**
2.3.1	Asset Replacement and Refurbishment	5.3.3 a)	
2.3.2	Asset Life Cycle Risk Management	5.3.3 b)	
3	**Capital Expenditure Plan**	**5.4**	**Capital Expenditure Plan**
3.1	**Summary**	**5.4.1**	**Summary**
3.1.1	System Access	5.4.1	Summary
3.1.2	System Renewal	5.4.1	Summary

3.1.3	System Service	5.4.1	Summary
3.1.4	General Plant	5.4.1	Summary
3.1.5	Load and Generation Connection Capability	5.4.1 a)	
3.1.6	Total Annual Capital Expenditures by Category	5.4.1 b)	
3.1.7	Capital Expenditures Description by Category	5.4.1 c)	
3.1.8	Forecasted Material Capital Expenditures	5.4.1 d)	
3.1.9	Regional Planning Process	5.4.1 e)	
3.1.10	Customer Engagement Activities	5.4.1 f)	
3.1.11	System Development Expectations	5.4.1 g)	
3.1.12	Impact of Customer Preferences, Technology, and Innovation on Total Capital Cost	5.4.1 h)	
3.2	**Capital Expenditure Planning Process Overview**	**5.4.2**	**Capital expenditure planning process overview**
3.2.1	Capital Expenditure Planning Objectives	5.4.2 a)	
3.2.2	Non-Distribution System Alternatives	5.4.2 b)	
3.2.3	Prioritization Process, Tools and Methods	5.4.2 c)	
3.2.4	Customer Engagement	5.4.2 d)	
3.2.5	Prioritization of REG Investments	5.4.2 e)	
3.3	**System Capability Assessment for Renewable Energy Generation**	**5.4.3**	**System capability assessment for renewable energy generation**
3.3.1	Applications Over 10kW	5.4.3 a)	

3.3.2	Renewable Generation Forecast	5.4.3 b)	
3.3.3	Capacity of the System to Connect DER	5.4.3 c)	
3.3.4	Constraints	5.4.3 d)	
3.3.5	Constraints for an Embedded Distributor	5.4.3 e)	
3.4	**Capital Expenditure Summary**	**5.4.4**	**Capital expenditure summary**
3.4.1	Capital Spending Overview	5.4.4	Capital expenditure summary
3.4.2	System Access	5.4.4	Capital expenditure summary
3.4.3	System Renewal	5.4.4	Capital expenditure summary
3.4.4	System Service	5.4.4	Capital expenditure summary
3.4.5	General Plant	5.4.4	Capital expenditure summary
3.5	**Justifying Capital Expenditures**	**5.4.5**	**Justifying capital expenditures**
3.5.1	Overall Plan	5.4.5.1	Overall plan
3.5.2	Material Investments	5.4.5.2	Material investments
3.6	**Material Investments**	**5.4.5.2**	**Material investments**

The purpose of the DSP is to consolidate HOL's practices as they relate to the planning and execution of System Access, System Renewal, System Service and General Plan investments through the Asset Management Process (Section 2 Asset Management Process). These practices will be detailed throughout the DSP. The DSP details the forecast years' (2016-2020) capital spending activities and the planning processes through which they are identified and prioritized, activities relating to third party coordination and information on customer engagement.

Historically, HOL has produced an Annual Planning Report (APR) which covers the four main areas of planning described above, with a 20-year outlook, summarizing the outcomes of the process described in Section 2 of this DSP. As the DSP and the Annual Planning Report share a number of commonalities, the 2014 APR has been included in Attachment B-1(B), and is referenced throughout the DSP.

HOL's DSP has been divided into three sections as outlined in Chapter 5:

Section 1 – Distribution System Plan (corresponding to Section 5.2 of Chapter 5)

The first section of the Distribution System Plan is intended to provide the Ontario Energy Board (OEB) and stakeholders with a high level overview of the information filed within the DSP including key elements that affect rate proposals and sources of cost savings expected to be achieved, information on coordinated planning with third parties, and performance measurements for continuous improvement.

Section 2 – Asset Management Process (corresponding to Section 5.3 of Chapter 5)

The purpose of the second section is to provide the Board and stakeholders with an understanding of the direct links between the asset management process and the expenditure decisions that comprise the capital investment plan and how they impact operation and maintenance (O&M) expenditures. Included in this section is an overview of the process, a description of the assets managed, and details of HOL's optimization policies and practices as they related to asset replacements, testing, inspection and maintenance.

Section 3 – Capital Expenditure Plan (corresponding to Section 5.4 of Chapter 5)

The third and final section of the DSP details HOL's O&M expenditures and capital system investments that have been derived from the asset management process (described in section 2) and the capital expenditure planning process. Details included are in relation to the capital expenditure planning process, the capability of the system to connect new load and embedded generation, a summary of capital expenditures and O&M expenditures and justifications for projects and Budget Programs that meet the materiality threshold of $750k.

1.0.1 Corporate Strategic Direction & Asset Management Objectives

HOL's planning practices and Asset Management Process tie back to the Corporate Strategic Direction. Understanding of this framework provides context for the Distribution System Plan and is referenced throughout.

Mission

To create long-term value for our shareholder, benefitting our customers and the communities we serve.

Vision

To be a leading and trusted utility services company.

- Leading – consistently being among the top performers in the business, in every critical area of our operations; and being regarded as a credible and trusted voice in our industry, helping to shape policy, regulatory and operational responses to the critical issues of the day.
- Trusted – Trust is fundamental to HOL's success – a continuing belief among our stakeholders that we will deliver on our mission, reliably, in a transparent and accountable fashion.
- Integrated – realizing synergies and economies of scale in 'close to the customer' utility services, to create additional value for the company's shareholder, and savings and enhanced service to customers.

Strategy

With our mission and vision in mind HOL's goal is two-fold:

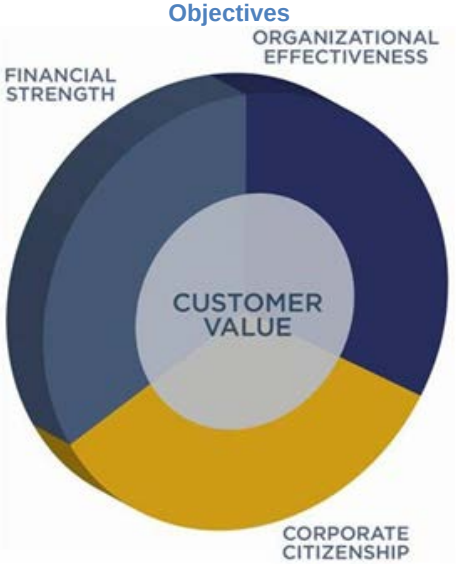
- To continue to fulfill our core mandate to provide a safe, reliable, affordable and sustainable supply of electricity to the homes and businesses that rely on us every day; and
- To ensure a more sustainable energy future for our community.

To achieve these goals, HOL's strategy is to put the customer at the centre of everything we do. Understanding and responding to the customer's needs and expectations – for service quality, cleaner energy, and greater control over the management of energy costs – will be key to HOL's continued success in an evolving landscape.

Corporate Strategic Objectives

To achieve our strategy, the plan is structured around four critical areas of performance that have driven our success to date, shown in Figure 1.0.1. In each of these areas, we have set one overreaching objective. These four areas of focus will continue to guide our activities throughout the current plan, but one, Customer Value, takes on central importance.

Figure 1.0.1 - Corporate Strategic Objectives



Customer Value – we will deliver value across the entire customer experience – by providing reliable, responsive and innovative services at competitive rates

Financial Strength – we will create sustainable growth in our business and our earnings – by improving productivity and pursuing business growth opportunities that leverage our strengths – our core capabilities, our assets and our people

Organizational Effectiveness – we will achieve performance excellence – by cultivating a culture of innovation and continuous improvement

Corporate Citizenship – we will contribute to the well-being of the community – by acting at all times as a responsible and engaged corporate citizen

Asset Management Objectives

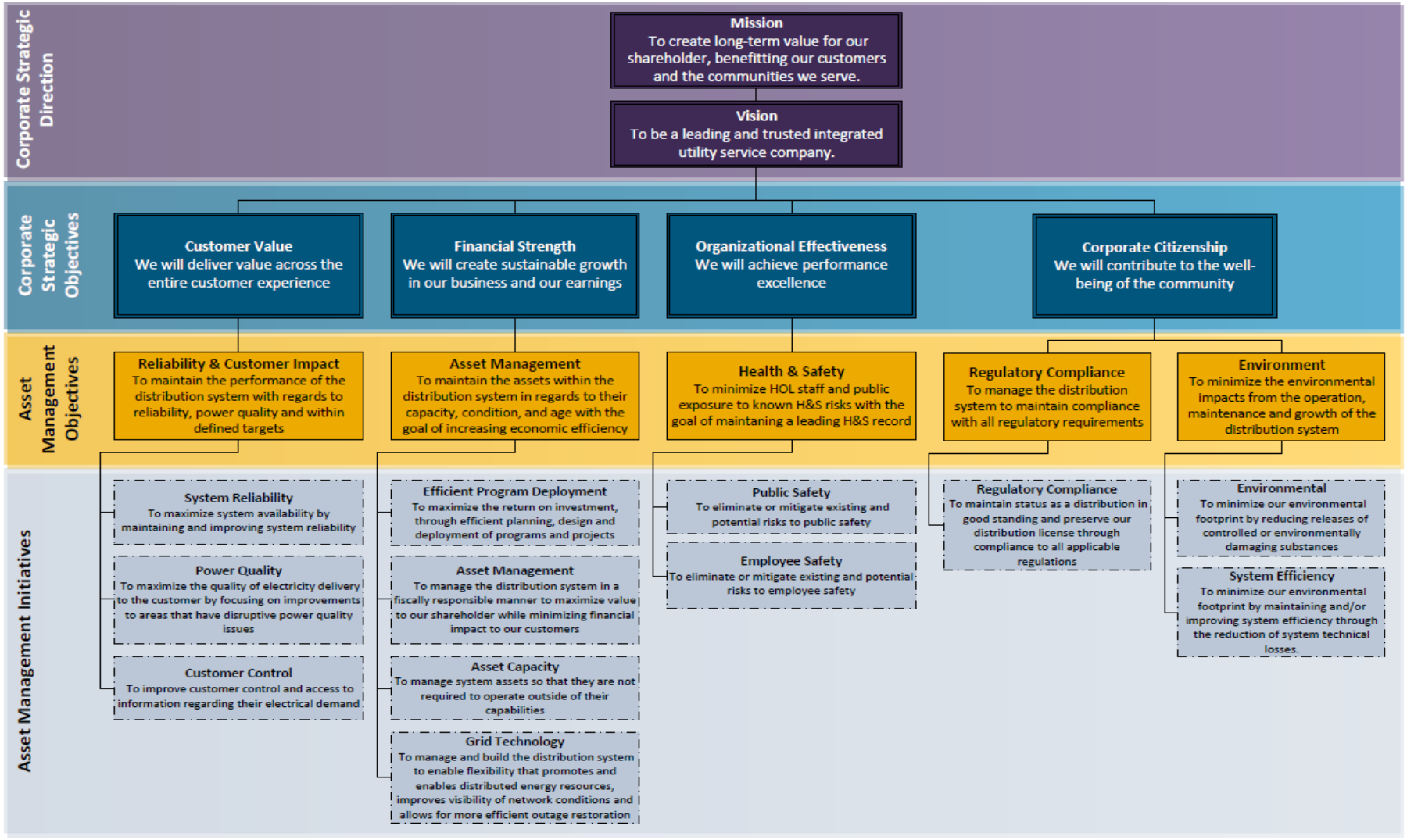
The goal of the Asset Management Process is to deliver a portfolio of projects which support the Key Areas of Focus in a transparent, consistent and sustainable manner. In this regard, there are five (5) key Asset Management Objectives, which have been identified in support of the Corporate Strategic Objectives.

Asset Management Initiatives

Support of the Asset Management Objectives is expressed in terms of initiatives. These are specific operational goals which are directly impacted by the work carried out under the Asset Management Process.

The hierarchy between the Corporate Strategic Direction through to the Asset Management Objectives is shown in Figure 1.0.2.

Figure 1.0.2 - Corporate Strategic Direction & Asset Management Objectives



1.1 Distribution System Plan Overview

The Distribution System Plan (DSP) overview provides a high level synopsis of the information that can be found in the DSP, providing context for the remaining document with regards to the capital expenditures, O&M expenditures and vintage of the information provided and the areas of cost savings found as a result of HOL's distribution system planning, i.e. - planning and execution of System Access, System Renewal, System Service and General Plant investments through the Asset Management Process.

1.1.1 Key Elements of the DSP

HOL's DSP details the planning process used by HOL as well as the process to take the system demographics and needs described to translate them into specific projects and expenditure plans. The DSP also addresses how productivity, lifecycle optimization, consultation with customers, coordination with third parties and requirements of Renewable Energy Generation (REG) play a key role in achieving Corporate Strategic Objectives of HOL.

Table 1.1.1 and Figure 1.1.1 show HOL's planned capital spending levels in each of the Ontario Energy Board's defined investment categories.

Table 1.1.1 - Forecast by Investment Category

Investment Category	$'000				
	2016	2017	2018	2019	2020
System Access (Gross)	36,263	35,156	35,132	35,835	36,551
System Renewal	41,033	31,823	36,491	35,980	35,718
System Service	22,235	33,957	29,518	30,473	33,314
General Plant	45,899	48,138	18,276	18,695	13,954
Grand Total	**145,430**	**149,073**	**119,418**	**120,982**	**119,538**

Figure 1.1.1 - Forecast by Investment Category

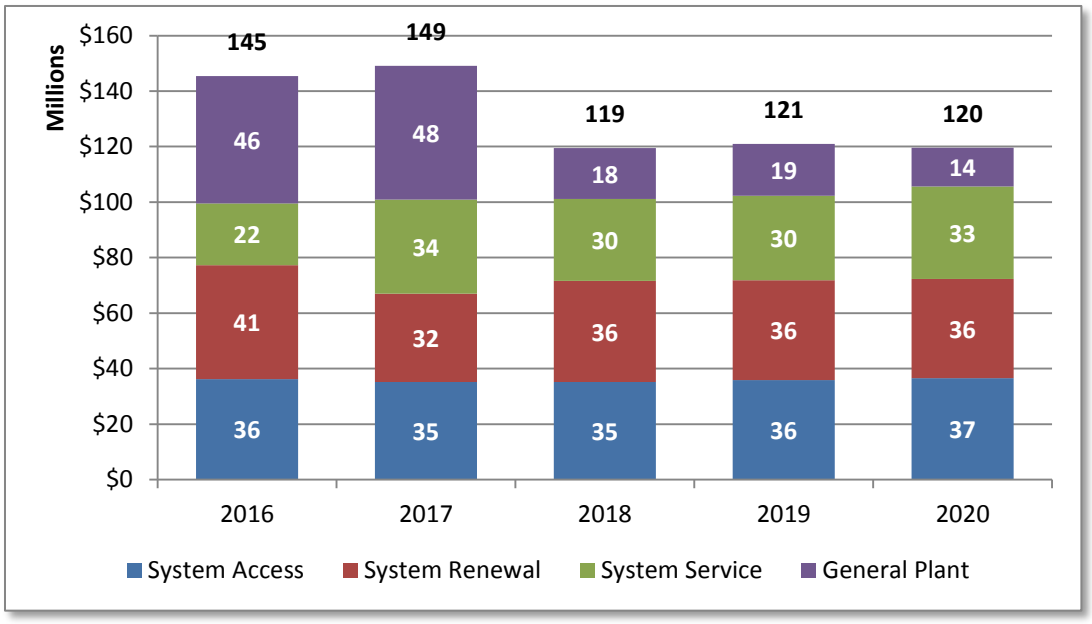
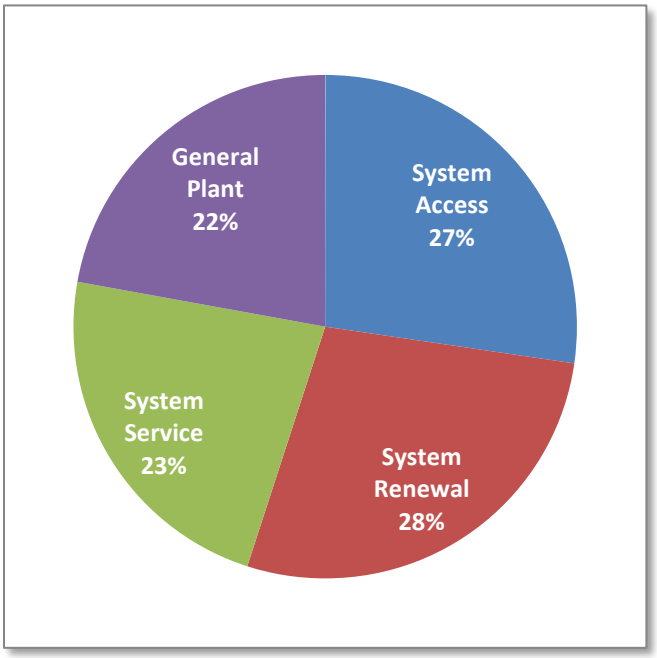


Figure 1.1.2 - Average Forecast Expenditure Distribution by Investment Category (2016-2020)



1.1.2 Sources of Cost Savings

The DSP details HOL's prioritizations and optimization of distribution system expenditures. Through the Asset Management process outlined in the DSP, HOL strives to level investments to minimize the risks associated with reliability and customer impact, safety, environment while improving on our service to our customers and providing increasing value to our shareholder. As displayed in Section 3 Capital Expenditure Plan, business cases are created to evaluate project alternatives so that the most effective, in regards to cost and benefits, solution is identified for implementation. Annual expenditures are then paced so that the timing of investments are optimized to minimize overall risk to HOL`s business values as much as possible for every dollar spent.

HOL is focused on productivity and developing efficiencies as sources of cost savings in both capital and O&M programs. Examples such as asset lifecycle optimizing and increased planning can result in real cost savings. The following list outlines a number of key areas of cost savings HOL is focusing on:

Operational productivity

HOL is striving to create a culture of continuous improvement. Whether through process improvement or by leveraging new technology, HOL has been, and continues to look for new ways to more efficiently provide the best possible service to our customers. The following is a list of the initiatives introduced at HOL:

- *Lean Method of Management* – A continuous improvement program focused on eliminating waste from business processes;
- *Corporate Productivity Scorecard* – Development of a suite of KPIs to measure and monitor productivity across the organization; and
- *CEO Productivity and Innovation Award* – Intended to recognize those teams and individuals who have driven a tangible or measureable productivity improvement.

These directly relate to the DSP through the following:

- Capital Execution Process Review

- In 2011 HOL completed a Lean review of our capital execution process from project initiation and design through to project closure. A cross functional team of employees involved in different aspects of projects was assembled to review the current state, identify issues and opportunities and make recommendations for implementation that would demonstrate improvements to how we do business.

- Aligned Staff Geographically
  - The Asset Management and Design groups were realigned to match the geographical structure of our construction and maintenance groups. This improved communication and quality of projects from planning through to execution.
- Centralized Scheduling
  - HOL undertook a review of its scheduling systems for capital and maintenance programs and determined that greater efficiencies could be derived from implementing a centralized scheduling system.
- Multi-Disciplined System Designer
  - HOL is working towards changing from a model with functional specific designers to a system with multi-disciplined designers to enable designers to manage all aspects of a project.
- Operational Process Liaison Committee
  - A new cross functional committee was established within the Operations group consisting of staff and management from Design, Scheduling, Service Desk and Construction. The mandate of this cross functional group is to take a look at core business processes that cut across departmental lines to look for opportunities to improve overall efficiency and effectiveness of operational processes.
- Unit Bills
  - Unit bills are lists of material and construction components that are used to create estimates for distribution capital projects. In the old process, a Designer was required to input each unit of material and labour into JD Edwards (HOL Enterprise System) on a job by job basis. This made the task of creating material lists for projects very labour intensive. To reduce this, in 2014 Distribution Design undertook the task of assigning labour and trucking units to each overhead

standard. To avoid the task of building material lists for each overhead project, each standard had a list or unit bill of material, labour and trucking created for it.

Planning Effectiveness

Through an ever improving inspection, testing and maintenance planning and project prioritization process HOL has developed a plan that paces spending while still meeting the reliability requirements of the distribution system. The short term, 5-year plan is tied into the long-term 20-year plan which is developed to align with HOL's Corporate Strategic Objectives: Customer Value, Financial Strength, Organizational Effectiveness, and Corporate Citizenship. As part of the continuous betterment of the planning process, HOL is implementing a new asset investment planning software tool which will improve data flow, asset condition models and will take HOL to the next level of asset analytics and project optimization.

Increased Use of New Technology

When replacing assets at the end of life, or evaluating projects to improve reliability, HOL incorporates new technologies where feasible. This includes:

- Replacing end of life switches with a smart, Supervisory Control and Data Acquisition (SCADA) controlled switches capable of remote operation thus reducing crew and truck time previously required for switching and power restoration.
- Installing fault current indicators (FCIs) based on past experience and evaluation of single line diagrams for ideal installation locations. The smart FCIs report is communicated back to system office through the SCADA network which provides indication to the operators as to the location of the fault, speeding up switching and restoration time by reducing the time spent on trouble shooting.
- HOL is trialing cable rejuvenation through the use of cable injection to extend the life of direct buried XLPE cables. The cable injection process proves to be significantly more cost effective compared to the traditional asset replacement. Should this program prove successful, HOL will be able to redirect the savings obtained through injection versus replacement in the cable replacement program to other areas of the asset management process, helping to close the gap between the needs identified and available expenditure levels.

- HOL has invested in an Asset Investment Planning initiative to implement Copperleaf's C55 program. The C55 program will allow HOL to automate the optimization process further improving the ability to mitigate risks and increase benefits amongst a variety of project ideas. This is achieved by comparing all possible scenarios of projects which fit within the user specified constraints and recommends a list of projects which best meets the Corporate Strategic Objectives.
- HOL has recommended the acquisition of a Mobile Workforce Management (MWM) tool to address three core requirements; Unified Dispatching, Intelligent Job and Route Optimization, and Performance Management capability. MWM tools will enable the following:
    - Increase in daily job completion rates
    - Improve on-time performance
    - Decrease kilometers driven and reduce fuel consumption
    - Cut overtime
    - Reduce field service teams administrative load
    - Reduce morning preparation time before trucks roll
    - Reduce inbound "Where's My Tech" calls
    - Reduce unnecessary truck rolls
    - Improve customer satisfaction
    - Significantly enhance Performance Management discipline

Implementation of today's MWM tools will allow HOL to enjoy the benefits of improved productivity and cost reductions, while also staying a step ahead of the increasing demands of its customers.

Through the use of these technologies a reduction of manual efforts is achieved, thereby creating better efficiencies and overall better reliability. They also allow for greater O&M savings than their initial investments thus reducing the overall lifecycle cost.

Detailed Short Term Planning

Having multiple years' worth of projects identified and justified allows design packages to be created in advance, creating a more adaptive plan. Should a project be advanced or deferred due to third party constrains not previously know, crews are able to quickly redirect their time to a project whose construction package is ready for implementation, minimizing down time. As well, by having a detailed short term plan improves coordination with third parties by enabling HOL to start communications far in advance of work being scheduled.

Storm Hardening

The Storm Hardening project was a project identified to assess the current state of trees in proximity to HOL's overhead infrastructure and develop new trimming standards that would decrease the impact of tree contact cause outages during adverse weather conditions. Over the course of three years HOL inspected all of the overhead spans of conductor in its service territory. The data gathered is being used to evaluate the current tree trim cycles and look for opportunities to improve the effectiveness of the program with more information on tree species for each span. Also identified through the inspections were 2,650 spans with branches overhanging the conductor. This overhang increases the risk of an outage caused by fallen branches. To reduce this risk, HOL is working to eliminate all vegetation overhangs in the system through a dedicated vegetation management project. Reducing the number of outages caused by tree contacts will save resource costs associated with responding to an outage as well as the cost of repairing or replacing damaged equipment as a result of the fallen branches. This will also have a positive impact on reliability. Moving forward, the elimination of overhang will become part of HOL's tree trimming standards and will be maintained as part of regular trim cycles.

Committee Participation with Third Parties

HOL continues to actively participate in committees with third parties, which assist HOL in identifying deficiencies and improvements that allow the company to service customers with a reliable, cost effective supply of electricity at the lowest possible cost. HOL is a member of many technical and standards committees which allows the company to deploy best practices and processes. These committees include:

- Electricity Distributors Association (EDA) Operations Council;
- Electrical Contractors Association (ECA) Ottawa;
- Canadian Standards Association (CSA) Standards committees;
- Electrical Safety Authority (ESA);and
- Canadian Electricity Association (CEA)

Centre for Energy Advancement through Technological Innovation (CEATI)

CEATI is a user-driven organization that is committed to providing technology solutions to its electrical utility participants, who are brought together to collaborate and act jointly to advance the industry though the sharing and development of practical and applicable knowledge. These innovations address issues pertinent to day-to-day operations, maintenance, and planning.

In addition to enabling information exchange through topic-driven interest groups and industry conferences, CEATI International brings participants together to collaborate on technical projects. The outcome of these projects has great impact on the infrastructure that HOL plans to use in the future. HOL is a member of numerous interest groups and specialized task forces within CEATI. They are joined by over 120 participating organizations which include electric and gas utilities, governmental agencies, and provincial and state research bodies such as: Hydro One Networks Inc., PowerStream Inc., Toronto Hydro Electric System Limited, National Research Council, Ontario Power Generation, and Ontario Power Authority.

1.1.3 DSP Period

The DSP covers the historical period from 2011 to 2015 and outlines the forecast years 2016 to 2020.

1.1.4 Vintage of Information

All information and details provided have been compiled throughout 2014, unless otherwise stated, and should be considered as current.

1.1.5 Asset Management Process Updates

HOL has not previously filed a DSP, and as such there are no changes since the last filing.

1.1.6 Aspects Contingent on Ongoing Activities or Future Events

HOL is currently involved in the Integrated Regional Planning Process (IRRP) (1.2.1.1 Integrated Regional Resource Planning Process) for the Ottawa area, the results of which are currently not final. A number of regional and bulk system needs are currently being studied to determine optimal solutions. The results of the study may recommend specific projects that could impact capital expenditures over the forecast period of 2015 through 2020.

Through HOL's annual Capacity Plan evaluation process, a need for additional capacity in the Lisgar TL station area was identified. HOL opted to engage Hydro One through the IRRP, for the upgrade of the two station transformers to meet the capacity requirements. Hydro One is currently creating estimates for this work so the final costs are not yet determined, and it is anticipated that expenditures will be required within the forecast period of 2015-2020.

Also engaged through Regional Infrastructure Planning (RIP), HOL has a number of station projects identified in the forecast period whose costs are dependent on the outcome of Hydro One Network Inc. evaluation and estimating process – Connection & Cost Recovery Agreements (CCRA), timelines of which have not yet been determined. Refer to 3.4.5 General Plant for more details on the forecasted expenditures.

1.2 Coordinated Planning with Third Parties

HOL continues to actively participate in consultations with third parties, which assist HOL in identifying deficiencies and improvements that allow the company to service customers with a reliable, cost effective supply of electricity at the lowest possible cost. HOL consults with customers, the transmitter, the Ontario Power Authority (OPA) (now Independent Electricity System Operator (IESO)), local distribution companies (LDCs), the City of Ottawa, and other third parties to better coordinate infrastructure planning now and into the future. These consultations are described in detail below.

1.2.1 Consultations

The following sections provide details on the various groups that HOL consults with in relation to the coordination of infrastructure planning.

1.2.1.1 Integrated Regional Resource Planning Process

HOL is currently involved in an Integrated Regional Resource Planning (IRRP) process which is being developed by the IESO (includes former OPA). The IRRP began in 2011 but has since been updated due to the OEB's adoption of the Planning Process Working Group report in 2013.

The IRRP process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission

Assessment Criteria (ORTAC), and develops integrated solutions to address any needs that are identified. These include: conservation, demand management, distributed generation, large-scale generation, transmission, and distribution. HOL has provided the IESO (OPA) with an updated long term load forecast, which is provided in Appendix A. The forecast outlines several transmission and distribution stations that will exceed their capacity limitations within the near, medium, and long term. HOL also contributes to the IRRP by identifying feasibility limitations within the planning area that may not be known to the working group (i.e. Greenbelt). The IRRP is to address the arising needs, identifying cost effective and viable solutions. The working group, which consists of the IESO (OPA), HOL, Hydro One Network Inc., and Hydro One Distribution, holds several meetings throughout the year to discuss progress on the study.

The final deliverables from this study are:

- Handoff letters from the OPA to direct the implementation of near term actions; Delivered on June 27th, 2014, Appendix B
- Final 20 year IRRP report; expected in Q1 2015
- Handoff letters from the IESO (OPA) to implement actions addressed via the IRRP report; expected in Q1 2015

1.2.1.2 Customer Engagement

HOL recognizes customer value at the centre of its Corporate Strategic Objectives and annually engages customers to shape the Corporate Strategic Direction and incorporate their feedback into planning of the distribution system. HOL engages customers with two surveys; the Hydro Ottawa Customer Satisfaction Survey (referred to as the SIMUL Survey) and a Touch Logic Survey. The results of these surveys are used to identify areas of improvement and benchmark HOL's accomplishments against results of other utilities. Further details on HOL led customer engagement activities that have a direct impact on the DSP are discussed in section 3.1.10 Customer Engagement Activities.

1.2.1.3 E8 Smart Grid Working Group

The OEB established the E8 Smart Grid Working Group in 2012 in order to provide a forum for LDCs to share their experiences relating to smart grid technologies. The working group discussions focus on:

- Sharing views, strategic thinking, and development of investment drivers
- Verifying technology specifications
- Examining processes and methodologies
- Identifying business and technical challenges with developing smart grid technologies
- Pursuing opportunities to share these experiences with other LDCs

The members of the working group include the OEB, Hydro One, and the 8 largest LDCs in Ontario which are: HOL, Enersource, Hydro Mississauga Inc., Hydro One Brampton Networks Inc., London Hydro Inc., PowerStream Inc., Veridian Connections Inc., Toronto Hydro Electric System Limited, and Horizon Utilities Corp.

Each LDC has the opportunity to host a meeting and highlight its own smart grid endeavours. HOL continues to benefit from the furthered understanding of smart grid technologies and incorporates these technologies into HOL's system through future planning processes.

1.2.1.4 City of Ottawa Utility Coordinating Committee (UCC)

The UCC provides a forum for communication between invited utilities and the City of Ottawa in order to ensure safe and efficient management of the infrastructure within road allowances and other right-of-ways. Every fall, HOL provides the road authority with their proposed major works plan for the following year to gain efficiency enhancements through improved construction scheduling coordination, damage prevention initiatives, and development of standards.

The primary functions of the committee are:

- Jointly plan construction activities
- Set technical standards
- Protect plant
- Provide a quick communication network
- Maintain a central registry
- Resolve disputes
- Assist the road authority with proposed utility installation permit processes

The committee members are: City of Ottawa, HOL, Hydro One Networks Inc., Heavy Construction Association, Enbridge Gas Distribution, Birch Hill Telecom, Bell Canada, Rogers Cable Communications, Telus Communications, and Allstream.

1.2.1.5 Hydro One - LDC Generation Working Group

The LDC Generation Working Group provides an opportunity for its members to discuss, develop, and potentially adopt policies and best practices relating to LDC distributed generation connections. This allows for better management of the grid when using distributed energy resources, plus effectively and consistently delivering services to generators. The Working Group discussions have also addressed the operational challenges being experienced due to the increase of connected distributed generation. The primary areas addressed by the Working Group are:

- Program administration, both internally within the LDC, and externally to the customer
- Inter-utility communications (especially with embedded LDCs and the Transmitter)
- Engagement with the generation industry
- Engagement with the OEB, IESO (includes the former OPA), and ESA as needed on policy and procedural issues
- Forecast of and adaptation to generation trends and needs
- Technical concerns, resolutions, and standards with respect to:
    - Generation connection: enhancing the customer's experience
    - Grid management: planning and assessing available generation capacity
    - Operations: outage planning and restoration, permitting temporary run on alternate feeders
    - Inspections and maintenance: ensure safety of people and assets
    - Assessing impact of distributed generation on existing customers and the distribution system

The working group meets quarterly and is comprised of: Hydro One Networks Inc., HOL, Kingston Hydro Corp., Horizons Utilities, Newmarket-Tay Power Distribution Limited, Greater Sudbury Hydro Inc., PowerStream Inc., Toronto Hydro Electric System Limited, London Hydro Inc., and the OPA (now IESO).

HOL believes that continued discussions with the Working Group will improve future planning and operating processes related to the integration of REGs.

1.2.1.6 Ontario Regional Common Ground Alliance (Ottawa)

The Ontario Regional Common Ground Alliance (ORCGA) was established after the amalgamation of the Ontario Prevention Committee and the Third Party Damage Prevention Task Force. It was formally recognized by the Common Ground Alliance (CGA) in 2003 as a partner. The ORCGA develops best practices which represent a dynamic statement of the type of activities that ORCGA believes would provide optimum levels of due diligence towards preventing damage to underground infrastructure. Beyond establishing standard practices, the committee allows for a forum between its members to discuss upcoming projects and local issues. The ORCGA actively tries to improve safety to all stakeholders by raising awareness about safe digging practices via Dig Safe Month in Ontario.

The committee members are: ORCGA, Ontario One Call, HOL, BayCadd Solutions, Promark-Telecon, Enbridge Gas Distribution, Broadband Maintenance, Bell, Hydro One Networks Inc., Goldie Mohr Limited, Drain All, Aecon Utilities, City of Ottawa, TransCanada Pipelines, TransNorthern Pipelines, TSSA, Oakwood Renovations, Marathon Drilling, Bell, UES, Dunda Powerline, and Taggart Construction.

HOL ensures that these standards and processes are used in its practices and through the forum discussions, actively plans future construction activities with the committee members.

1.2.1.7 Greater Ottawa Home Builders Association (GOHBA) – Builder Developer Council (BDC)

GOHBA represents home building and renovation professionals in the Greater Ottawa area with a primary goal of delivering quality housing for Canadians. HOL attends the BDC monthly meetings to take note of and provide input on development plans. The benefits of this council are:

- Customers provide feedback on HOL's practices
- HOL provides insight into developments in order to minimize cost and deliver a timely supply
- HOL provides updated standards and financial changes that may affect projects

- Future development plans allow HOL to forecast load growth and plan infrastructure in order to supply the area

The BDC has over 30 members representing home developers, law firms, and utilities. These members include: GOHBA, HOL, Bell Canada, Rogers Cable Communications, Minto, Mattamy Homes, Walton Development, Vice & Hunter LLP, and Borden Ladner Gervais LLP.

1.2.2 Deliverables

The numerous consultations between HOL and the various third parties described in Section 1.2.1 above continue to be ongoing. The outcome of these efforts result in better understanding and coordination between the various parties involved. Any final deliverables that arise from the coordinated efforts are used in HOL's planning process and capital expenditure plans.

At this time, the IRRP has produced a final deliverable in the form of a handoff letter from the OPA (now IESO) to Hydro One Networks Inc. as seen in Appendix B. This letter details the initiation of development work on near and mid-term transmission solutions to meet the needs identified by the working group. Specifically, the letter contains two transmission solutions that have been identified in impacting HOL's capital expenditure plan. These solutions will be developed and implemented by Hydro One Networks Inc. Currently, the date and cost to HOL is not known and it is unlikely that material investment will be identified for this Application's Test Year period. However, the date and costs of this work has the potential to fall within HOL's Forecast Years.

1.2.3 IESO Letter of Comment – HOL's REG Investments Plan

As described in Chapter 5, the IESO Comment Letter, which can be found in Appendix C, outlines the IESO's assessments of HOL's REG Investments Plan including:

- The applications the IESO has received from renewable generators through the Feed-In-Tariff (FIT) program for connection in the HOL distribution service area;
- Whether HOL has consulted or participated in planning meetings with the IESO;
- The need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- Whether the REG investments proposed in the DSP are consistent with any RIP.

1.3 Performance Measurement for Continuous Improvement

HOL uses Key Performance Indicators (KPI) to measure continuous improvement in asset management planning, capital investment planning and in customer oriented performance. These indicators include quantitative measures to monitor the effectiveness of utility's planning processes, efficiencies in carrying out those plans, as well as identifying shortfalls as areas for continuous improvement. Table 1.3.1 outlines the key performance indicators, by category, which are described in detail in the following sections.

Table 1.3.1 - Key Performance Indicators by Category

Category	Key Performance Indicator	Sub KPI
1.3.1.1 Customer Oriented Performance	1.3.1.1.1 Customer Engagement	
	1.3.1.1.2 System Reliability Performance Indicators	o SAIFI o SAIDI o CAIDI o FEMI $_{10}$
	1.3.1.1.3 Worst Feeder Analysis	
	1.3.1.1.4 System Average RMS Variation Frequency Index (SARFI)	
1.3.1.2 Cost Efficiency & Effectiveness	1.3.1.2.1 Cost Efficiency	
	1.3.1.2.2 Labour Utilization	o Productive Time o Labour Allocation
1.3.1.3 Asset Performance	1.3.1.3.1 Defective Equipment Contribution to SAIFI	
	1.3.1.3.2 Health, Safety and Environment	
1.3.1.4 System Operations Performance	1.3.1.4.1 Stations Exceeding Planning Capacity	
	1.3.1.4.2 Feeders Exceeding Planning Capacity	
	1.3.1.4.3 Stations Approaching Rated Capacity	
	1.3.1.4.4 Feeders Approaching Rated Capacity	
	1.3.1.4.5 System Losses	

1.3.1 Distribution System Planning Process Performance Indicators

The following sections describe the quantitative KPIs used by HOL to monitor the quality of the planning process and the efficiency with which the plans are implemented and the extent to which the planning objectives have been met.

1.3.1.1 Customer Oriented Performance

HOL continuously seeks feedback from customer on their satisfaction with the services provided by HOL. The customer satisfaction levels have proven to be greatly impacted by the distribution system's service reliability. Where gaps are found, the appropriate actions are identified to address the issues. Service reliability is integral to all work undertaken as part of system planning and asset management. Annually, as part of the Annual Planning Report (see Attachment B-1(B)), HOL undertakes a thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

1.3.1.1.1 Customer Engagement

HOL recognizes customer value at the centre of its Corporate Strategic Objectives and annually engages customers to shape the Corporate Strategic Direction and incorporate their feedback into planning of the distribution system. HOL engages customers with two surveys; the annual Hydro Ottawa Customer Satisfaction Survey (referred to as the SIMUL Survey) and monthly Touch Logic Surveys. The results of these surveys provide HOL with KPIs which HOL uses to identify areas of improvement and benchmark HOL's accomplishments against results of other utilities.

1.3.1.1.2 System Reliability Performance Indicators

HOL tracks system reliability performance using the following indicators:

System Average Interruption Frequency (SAIFI)

This index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area. In words, the definition is:

$$SAIFI = \frac{Total\ number\ of\ customer\ interruptions}{Total\ number\ of\ customers\ served}$$

This index is reported both including and excluding Loss of Supply (LoS). *SAIFI including LoS* provides information as to the total interruptions which are seen by the 'average' customer. *SAIFI excluding LoS* indicates the 'average' customer interruptions which are the result of causes under the direct control of HOL.

HOL's target is always to reduce SAIFI. Reliability driven sustainment projects along with better defined testing, inspection and maintenance programs will help to reduce the number of outages experienced.

System Average Interruption Duration Index (SAIDI)

This index is designed to provide information about the average time customers are interrupted. In words, the definition is:

$$SAIDI = \frac{Total\ hours\ of\ customer\ interruptions}{Total\ number\ of\ customers\ served}$$

This index is reported both including and excluding Loss of Supply (LoS). As with SAIFI, the *SAIDI including LoS* provides information as to the total duration of interruptions which are seen by the 'average' customer whereas *SAIDI excluding LoS* provides an indication as to the duration which the 'average' customer is interrupted as the result of causes under the control of HOL.

HOL's target is always to reduce SAIDI. Increased investments in system automation and new equipment trials will help expedite restoration efforts after outages occur.

Customer Average Interruption Duration Index (CAIDI)

CAIDI represents the average time required to restore power to the average customer per sustained outage. In words, the definition is:

$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{Total\ hours\ of\ customer\ interruptions}{Total\ number\ of\ customer\ interruptions}$$

Feeders Experiencing Multiple Sustained Interruptions ($FEMI_n$)

This index represents the number of feeders experiencing sustained (greater than 1 minute) outages greater than or equal to value n; current reporting is done for n=10. It is a customer

centric measure as it provides an indication as to which regions have seen high localized issues. $FEMI_{10}$ is reported excluding Scheduled Outages as well as Loss of Supply, to more accurately track regions seeing issues, as opposed to including regions seeing multiple outages due to maintenance, repair and upgrade activities.

HOL's target is always to reduce FEMI. Reliability driven sustainment projects as well as better defined testing, inspection and maintenance programs will help to reduce the number of outages experienced.

1.3.1.1.3 Worst Feeder Analysis

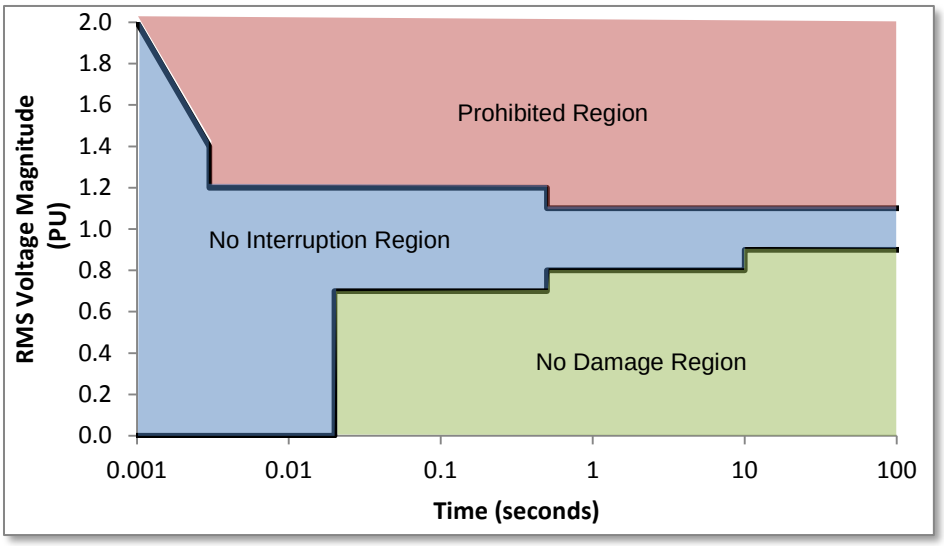
In 2011, a standard method to determine the "Worst Feeders" was defined. This method takes into consideration the duration, frequency and number of sustained outages as well as the number of momentary (duration < 1min) interruptions a feeder experiences. See Appendix D for details on how these factors are incorporated in the overall determination of the Worst Performing Feeders. Annually, based on the Worst Feeder Methodology, the 10 worst feeders are evaluated and potential improvements to the feeders are proposed.

The worst feeder program is designed to address short term reliability issues in an immediate time-frame. All work identified in the previous year review will be carried out in the following budget year, with targeted completion before the beginning of storm season. In the fall of 2015, identification and assessment of the worst feeders will again be carried out and appropriate actions will be undertaken to improve performance of the identified circuits.

1.3.1.1.4 System Average RMS Variation Frequency Index (SARFI)

The System Average Root Mean Square (RMS) Variation Frequency Index (SARFI) is an indicator of system power quality which measures the average number of voltage sags on the system. Poor voltage is considered to be outside ±6% of the system nominal voltage and it is HOL's objective to maintain voltage within these tolerances and below the prohibited region of the Information Technology Industry Council (ITIC) curve (see Figure 1.3.1). The target is to put corrective measures in place as soon as possible.

Figure 1.3.1 - ITIC Curve



1.3.1.2 *Cost Efficiency & Effectiveness*

On an annual basis, HOL uses the cost efficiency and labour utilization KPIs to report on the progress, efficiency and effectiveness to monitor the effectiveness of utility's planning processes, efficiencies in carrying out those plans, as well as identifying shortfalls as areas for continuous improvement.

1.3.1.2.1 Cost Efficiency

Cost Efficiency is an indicator of the amount of planned capital activities as a ratio to actual capital activities performed throughout the year. Cost efficiency is strictly a measure of all planned projects in System Renewal and System Service Investment Categories, but does not include System access or General Plant investments. Completion of the planned capital projects are monitored through HOL's financial system. Deviations from the project budget are managed through a change request process that must be justified and approved. Representatives from scheduling, construction, engineering and design meet on a bi-weekly basis to prioritize on-going and upcoming work in order to ensure work is completed on time and within budget. The target of the cost efficiency indicator is to achieve 100% completion of the annual planned work within the approved budget.

1.3.1.2.2 Labour Utilization

HOL tracks labour utilization performance using the following indicators:

Productive Time

Productive time represents the total regular hours charged to a work order as a ratio to total regular hours. The target of the productive time indicator is to maximize this index by identifying and improving efficiencies.

$$Productive\ Time = \frac{Percent\ of\ Billable\ Hours}{Total\ Regular\ Hours}$$

Labour Allocation

The labour allocation index represents the amount of labour spent on capital activities as a ratio to the total productive time. The target of the labour allocation indicator is to ensure that the appropriate amount of time is spent on Capital activities versus OM&A type activities as per annual work plans.

$$Labour\ Allocation = \frac{Percent\ of\ Labour\ Time\ on\ Capital\ Activities}{Total\ Productive\ Time}$$

1.3.1.3 ***Asset Performance***

HOL tracks asset performance using the following KPIs:

1.3.1.3.1 Defective Equipment Contribution to SAIFI

This indicator tracks the contribution of defective equipment outages by asset class to the overall system SAIFI per 100 customers (SAIFI x 100). HOL's objective is to reduce the number of interruptions caused by defective equipment from year to year.

1.3.1.3.2 Health, Safety and Environment

The Health & Safety and Environment indicator tracks the number of public safety concerns and the amount of oil spilled into the environment. Public safety concerns and oil spills are addressed immediately; therefore no specific objective has been set, as the goal is to simply reduce these numbers.

1.3.1.4 *System Operations Performance Indicators*

HOL tracks system operation performance using the following KPIs:

1.3.1.4.1 Stations Exceeding Planning Capacity

This indicator is defined by the percentage of stations with a summer peak operating above 100% of their planned capacity rating.

The planned capacity rating is defined as the sum of either the transformers' 10 day LTR or the allowable top load rating if there is no published LTR for the remaining transformers following a single contingency loss of the largest element within the substation (N-1 contingency). An N-1 contingency for a station is defined as the loss of the largest transformer within the station. Note that for stations with a single supply and a single transformer, the planning capacity rating is considered to be the rated capacity of the single unit (10 day LTR or allowable top load rating if there is no published LTR).

1.3.1.4.2 Feeders Exceeding Planning Capacity

This indicator is defined by the percentage of feeders with a summer peak operating above 100% of their planned capacity rating.

The planned capacity rating for a feeder takes three factors into consideration:

1. Coordination with lo-set instantaneous protection;
    - Under normal pre-contingency operating conditions, a feeder cannot be loaded above a level that would result in the lo-set instantaneous protection preventing feeder restoration, see the description below for cold load pick up.
2. Feeder cold load pick up ability; and
    - Outage analysis indicates that the cold-load and hot load pick up phenomenon results in approximately 2-times the feeder pre-contingency loading at 0.2 seconds (trip time setting for lo-set instantaneous protection).

Voltage (kV)	Lo-set Inst. Pick Up (A)	Cold Load Factor	Feeder Load Limit (A)
4.16	600	2	300
8.32	600	2	300
12.47	700	2	350
13.2	1000	2.5	400
27.6	1000	2.5	400

3. Short term (8 hour) egress cable overload capabilities

- Under normal pre-contingency operating conditions, a feeder cannot be loaded above the nominal capacity rating of the cable. In addition, a feeder must be capable of backing up neighbouring feeder(s) in the event of failure of supply of the neighbouring feeder or other contingency conditions. For the purposes of providing back-up ability, it is assumed that the feeder will be required to operate in the abnormal configuration with post-contingency loading levels for up to 8 hours.

Voltage (kV)	Typical Egress Cable	Design Rating (A)	8hr Rating (A)
4.16	5kV 4/0 Cu PILC, buried in duct	285	330
8.32	15kV, 500 MCM Cu XLPE, direct buried	675	870
12.47	15kV, 500 MCM Cu XLPE, direct buried	675	870
13.2	15kV 500 MCM Cu PILC, duct bank	425	510
27.6	29kV, 750 MCM Al XLPE, duct bank	450	620
27.6	29kV, 1000 MCM Al XLPE, duct bank	500	685

Given the constraints outlined above, the following limits are used based on feeder egress cable type:

Voltage (kV)	Typical Egress Cable	8hr Loading Limit (A)	Cold Load Limit (A)	Planning Limit (A)	Limiting Factor
4.16	5kV 4/0 Cu PILC	330	300	300	Coordination between Lo-set instantaneous protection and cold/hot load pick-up
8.32	15kV, 500 MCM Cu XLPE	870	300	300	Coordination between Lo-set instantaneous protection and cold/hot load pick-up
12.47	15kV, 500 MCM Cu XLPE	870	350	350	Coordination between Lo-set instantaneous protection and cold/hot load pick-up
13.2	15kV 500 MCM Cu PILC	510	400	255	Ability to provide adequate back-up capability for neighbouring circuits
27.6	29kV, 750 MCM Al XLPE	620	400	310	Ability to provide adequate back-up capability for neighbouring circuits
27.6	29kV, 1000 MCM Al XLPE,	685	400	340	Ability to provide adequate back-up capability for neighbouring circuits

1.3.1.4.3 Stations Approaching Rated Capacity

This indicator is defined by the percentage of stations at or above 100% of the station rated capacity.

The rated capacity is defined as the sum of the top rating (10-day LTR or allowable flat rating should an LTR not be published) of all transformers within the station. If the loading on a transformer exceeds this limit it will cause accelerated loss of life.

1.3.1.4.4 Feeders Approaching Rated Capacity

This indicator is defined by the percentage of feeders at or above 90% of the rated capacity.

The rated capacity is defined as the egress cable 8 hour loading limit. If the circuits are loaded above this limit for longer than 8 hours it will cause overheating and accelerated loss of life.

1.3.1.4.5 System Losses

Distribution losses are defined in the *Ontario Energy Board's Distribution System Code* as: "energy losses that result from the interaction of intrinsic characteristics of the distribution network such as electrical resistance with network voltages and current flows".

1.3.2 Performance Summary

The following sections provide a summary of performance and performance trends over the historical period using the methods and measures identified above.

1.3.2.1 Customer Oriented Performance

HOL continuously seeks feedback from customer on their satisfaction with the services provided by HOL. The customer satisfaction levels have proven to be greatly impacted by the distribution system's service reliability. Where gaps are found, the appropriate actions are identified to address the issues. Service reliability is integral to all work undertaken as part of system planning and asset management. Annually, as part of the Annual Planning Report (see Attachment B-1(B)), HOL undertakes a thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

1.3.2.1.1 Customer Satisfaction

Customer value is at the centre of HOL's Corporate Strategic Objectives and customers are engaged annually to shape the Corporate Strategic Direction and incorporate their feedback into planning of the distribution system. HOL engages customers with two surveys; the Hydro Ottawa Customer Satisfaction Survey (referred to as the SIMUL Survey) and a Touch Logic Survey. The results of these surveys provide HOL with KPIs which HOL uses to identify areas of improvement and benchmark HOL's accomplishments against results of other utilities.

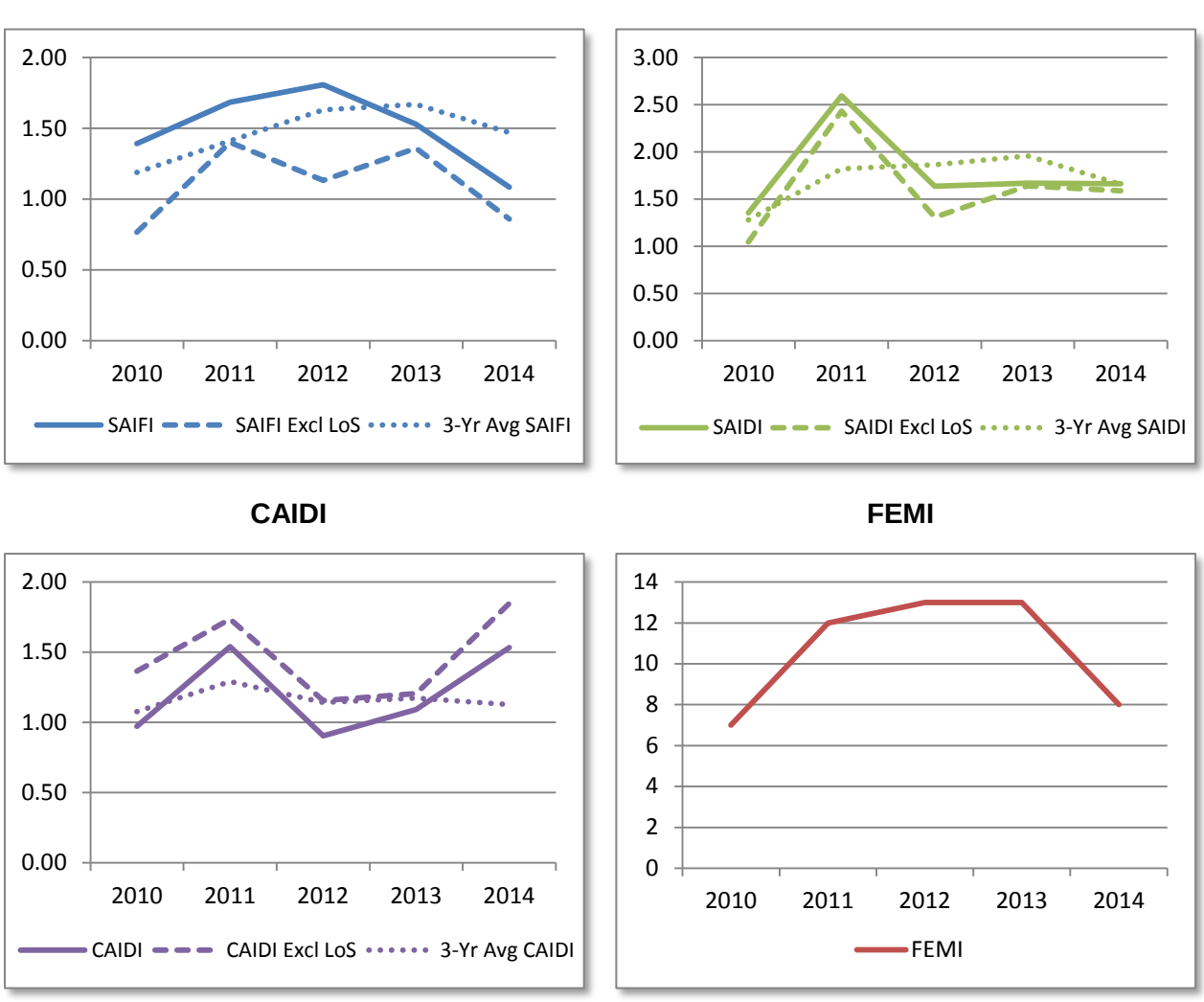
1.3.2.1.2 System Reliability Performance Indicator

HOL's reliability performance in 2014 improved from previous years. Interruption categories such as defective equipment and adverse weather, or storm related outages have been progressively trending worse and have exceeded the previous 3-year averages. Improvements to the asset management processes are underway making use of the new C55 Asset Investment Planning software to enhance our ability to prioritize end of life asset replacements. Maintenance, inspection and testing of existing assets will continue to be essential to ensure equipment operates as expected and to identify failures before they occur. Consideration of new ways of operating to reduce system susceptibility to storm damage and foreign interference is vital. In addition, investing in grid technologies will benefit reliability by reducing restoration times and aid in predicting system faults. HOL's objective is to improve the System Reliability Performance Indicators from year to year.

Table 1.3.2 - Reliability Performance Summary

KPI	2010	2011	2012	2013	2014
Annual SAIFI	1.39	1.68	1.81	1.53	1.08
SAIFI Excl LoS	0.77	1.40	1.13	1.36	0.86
3-Yr Average SAIFI	1.19	1.41	1.63	1.67	1.47
Annual SAIDI	1.35	2.60	1.64	1.67	1.66
SAIDI Excl LoS	1.05	2.43	1.31	1.64	1.59
3-Yr Average SAIDI	1.28	1.82	1.86	1.96	1.66
Annual CAIDI	0.97	1.54	0.90	1.09	1.53
CAIDI Excl LoS	1.37	1.74	1.15	1.21	1.85
3-Yr Average CAIDI	1.08	1.29	1.14	1.17	1.13
$FEMI_{10}$	7	12	13	13	8

Figure 1.3.2 - Reliability Performance - SAIFI, SAIDI, CAIDI & FEMI

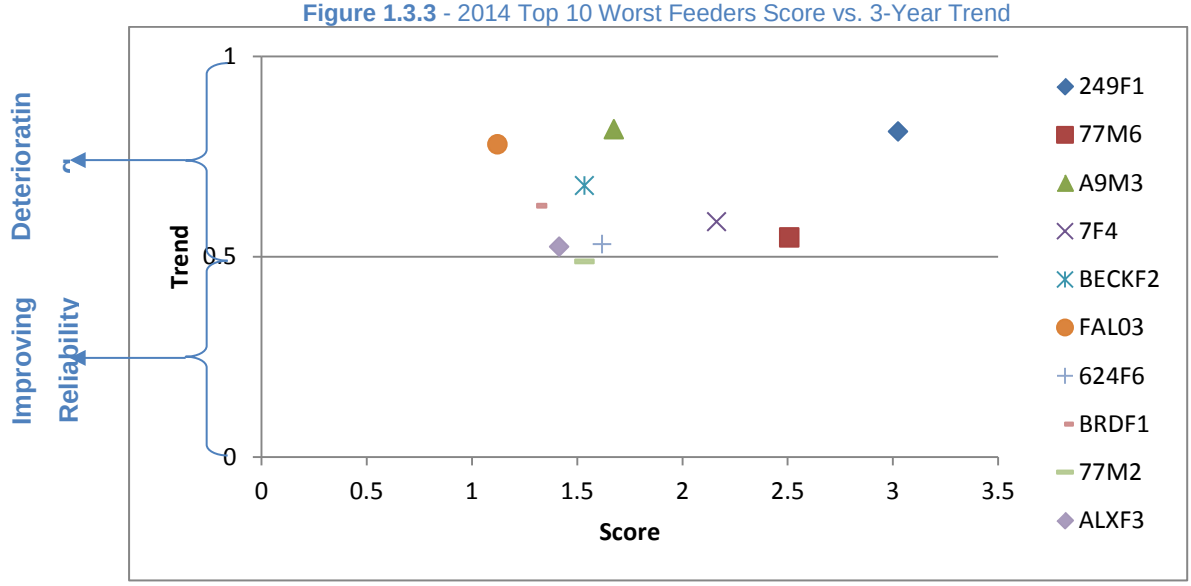


1.3.2.1.3 Worst Feeder Analysis

The Worst Feeder Methodology recommends tracking the worst feeders over a three year period to allow time for the improvements to be seen. The following figure outlines the 10 worst feeders for 2014 and where they sit in regards to Score versus Trend. Note that feeders that have a trend below 0.5 are seeing an improvement in reliability (1 feeder in 2014 – 77M2). Moving forward, the feeders will need to be continually tracked to determine whether the improvements made in the distribution have had an impact on improving the feeder's reliability. It is believed that there will be at least a three year lag in seeing the improvements on the feeder

– 1 year for the improvement to be implemented and the two following years to develop a new trend.

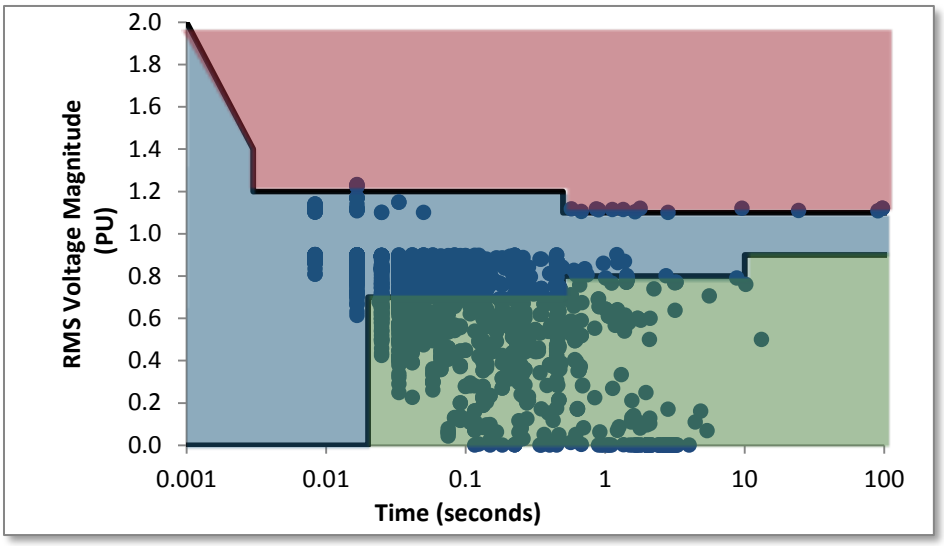
Figure 1.3.3 - 2014 Top 10 Worst Feeders Score vs. 3-Year Trend



1.3.2.1.4 System Average RMS Variation Frequency Index (SARFI)

The Information Technology Industry Council (ITIC) curve represents the 2013 RMS voltage variation events plotted against the variation envelope which single phase modern devices can tolerate. Of the 2820 events recorded in 2013, 16 fell within the prohibited region. The target is to put corrective measures in place as soon as possible. Of the 16 prohibited events, 11 were due to events on the transmission system (not owned by HOL), 2 were of unknown cause and 2 were due to HOL feeder faults.

Figure 1.3.4 - 2013 Power Quality Events ITIC Curve



*Note that 2014 Power Quality Events ITIC Curve is not yet available

1.3.2.2 Cost Efficiency & Effectiveness

On an annual basis, HOL uses the cost efficiency and labour utilization KPIs to report on the progress, efficiency and effectiveness to monitor the effectiveness of utility's planning processes, efficiencies in carrying out those plans, as well as identifying shortfalls as areas for continuous improvement.

1.3.2.2.1 Cost Efficiency

HOL identified the Cost Efficiency indicator in 2011 which annually targets to complete 100% of the work planned. In 2011 and 2012, the target was not achieved as a result of resources being unavailable due to the amount of plant failure repairs that were completed in those years. In 2013, HOL was able to complete an additional 5% above the target of the work planned as a result of unplanned work that was deemed required to increase the amount of risk mitigated.

Table 1.3.3 - Cost Efficiency

KPI	Target	2011	2012	2013	2014
Cost Efficiency	**100%**	94%	94%	105%	94%

1.3.2.2.2 Productive Time

HOL's annual target for the Productive Time indicator is to improve from the year before. The indicator which began being tracked in 2011, is affected by training, vacation and sick time, but

also does not account for the work completed on overtime. Further efficiencies will need to be identified in order to maximize this index and contribute to trending improvement.

Table 1.3.4 - Productive Time

KPI	2011	2012	2013	2014
Productive Time	70%	71%	69%	69%

1.3.2.2.3 Labour Allocation

HOL identified the Labour Allocation indicator in 2011 which aims to aid in the evaluation that the proper amount of time is spent on capital versus OM&A as per each year's annual plan. Labour allocation is hindered by aging infrastructure requiring increased hours spent on O&M activities

Table 1.3.5 - Labour Allocation

KPI	2011	2012	2013	2014
Labour Allocation	61%	55%	56%	59%

1.3.2.3 Asset Performance

HOL tracks asset performance using the following KPIs:

1.3.2.3.1 Defective Equipment Contribution to SAIFI

Asset failures impact the ability to provide reliable customer service to different extents. The impact of asset failures on system reliability is currently on an upward trend. The specific assets which are contributing to this trend include Underground Cable Attachments, Station Switchgear, Overhead and Underground Transformers, and Poles. Increased or more targeted asset replacement may be required to manage these assets such that they do not adversely impact system reliability performance. Trends are reviewed in HOL's Asset Management Planning Report as part of the Annual Planning Report (see Attachment B-1(B)) on an annual basis to establish a target for the frequency and the quantity of assets to be replaced.

Table 1.3.6 - Defective Equipment SAIFI per 100 Customers

Asset	2010	2011	2012	2013
U/G Cable - Polymer	5	10	4	2
Insulator	2	7	0.3	0.1
Station Switchgear	2	5	0	3
O/H Switchgear	4	4	3	6
U/G Cable Attachment	2	3	2	5
Station Transformer	1.2	1.2	2	0
U/G Switchgear	1	1	7	0.1
U/G Cable - PILC	0.7	0.6	0.6	1.5
O/H Transformer	0	0	1	2
Pole	0	0	1	4
U/G Transformer	1	0	3	3
Other	6	9	6	5
Total	25	41	30	32

*Note that 2014 Defective Equipment SAIFI per 100 Customers data is not yet available

1.3.2.3.2 Health, Safety and Environment

HOL reports to the Ministry of the Environment on oil spilled and the cost of remediation. Recent trends are seeing more leaking residential padmounted transformers which have increased the cost of remediation. This emphasizes the importance of active inspection and replacement of padmounted transformers to mitigate this environmental impact.

Table 1.3.7 - Health & Safety and Environment

		2010	2011	2012	2013
Public Safety	Number of Public Safety Concern (PSCs)	9	4	2	10
Oil Spills	Annual Oil Spilled (L)	1,262	1,225	3,249	5,828
	Annual Oil Clean up ($'000)	$378	$563	$465	$792

*Note that 2014 Health & Safety and Environment indicators are not yet available

1.3.2.4 System Operations Performance Indicators

System capacity is currently trailing load growth in the City of Ottawa; this has resulted in fifteen percent of the stations owned by HOL operating above their planning capacity rating set to ensure that adequate capacity is reserved for reliable operation during system contingency.

In 2013, three stations were loaded above their equipment ratings at system peak: Richmond North DS, Nepean TS and Hawthorne TS. Work to increase capacity at Richmond South DS is scheduled to begin in 2015 and will allow for better load balancing between Richmond North and South to alleviate the overload condition. The Hawthorne TS units are currently planned for replacement by Hydro One and load balancing at Nepean TS should resolve the slight overload seen in 2013. There is a positive trend being shown in the data: as capacity projects progress the system is seeing less stress since 2010.

Losses remained within the acceptable range of between 2% to 4%. HOL continues to work to reduce system losses through better system planning and the updating or replacement of equipment.

Feeders exceeding their planning ratings are within target (≤ 10%), but careful review and planning is being undertaken to ensure adequate backup is maintained to allow for secure and reliable delivery of power for HOL's Customers.

Table 1.3.8 - System Operations Performance Indicators

KPI	Target	2010	2011	2012	2013
Stations Exceeding Planning Capacity	≤ 5%	26% (20)	24% (22)	20% (18)	15% (14)
Feeders Exceeding Planning Capacity	≤ 10%	3.5% (28)	3.4% (27)	3.3% (26)	3.2% (22)
Stations Approaching Rated Capacity	zero	4.4% (4)	2.2% (2)	2.2% (2)	3.3% (3)
Feeders Approaching Rated Capacity	zero	0.4% (3)	0.5% (4)	0.5% (4)	0.3% (2)
System Losses	≤ 4.00%	3.12%	3.13%	3.60%	2.63%

*Note that 2014 System Operations Performance Indicators are not yet available

1.3.3 Effect of Key Performance Indicators on the DSP

HOL's Corporate Strategic Objectives and targets provide the framework for the DSP. The KPIs used to evaluate the company are defined by the Customer Oriented Performance indicators, the Cost Efficiencies & Effectiveness indicators, the Asset Performance indicators and the System Operations Performance indicators. Tracking of these KPIs will allow HOL to set benchmarks and milestones to ensure that the company objectives of continuous improvement are achieved across all areas of business.

2 Asset Management Process

The following sections outline HOL's Asset Management Process – the systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures. The information is intended to provide the Board and stakeholders with an understanding of the process, and the direct links between the process and the expenditure decisions that comprise the investment plan.

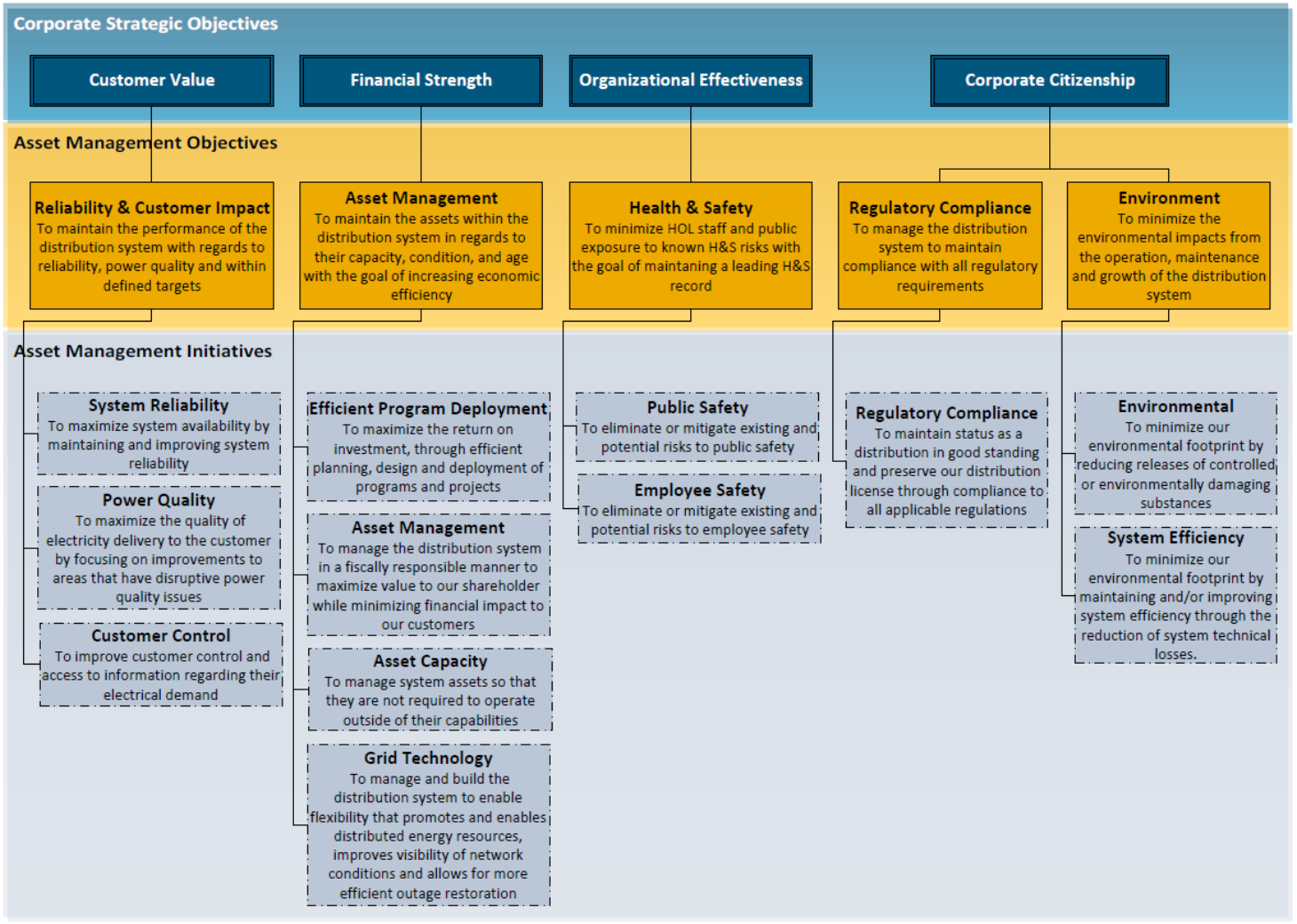
2.1 Asset Management Process Overview

The Asset Management Process Overview section details the Asset Management Objectives and each component in the Asset Management Process.

2.1.1 Asset Management Objectives

The Asset Management Process aligns with HOL's Corporate Strategic Direction by adhering to the Asset Management Initiatives that directly support the Corporate Strategic Objectives as outlined in Section 1.0.1. The hierarchy between the Corporate Strategic Direction through to the Asset Management Initiatives is shown in Figure 1.0.2. Figure 2.1.1 describes the Asset Management Objectives and the associated Asset Management Initiatives which drive the decision making through the Asset Management Process.

Figure 2.1.1 - Asset Management Objectives & Asset Management Initiatives



2.1.2 Asset Management Process Components

HOL's Asset Management Process, as shown in Figure 2.1.2, is a function of 5 difference phases:

1) Project Concept Definition (Section 2.1.2.1)
2) Project Evaluation (Section 2.1.2.2)
3) Project Prioritization (Section 2.1.2.3)
4) Project Execution (Section 2.1.2.4)
5) Risk Assessment & Review (Section 2.1.2.5)

The Project Concept Definition phase gathers all internal and external drivers to describe the needs of the organization. Concept projects are created to meet requirements, mitigate or remove risk, and reach goals and objectives.

The Project Evaluation phase defines project alternatives and creates business cases in support of the feasible alternatives. Unless mandated, project alternatives are evaluated and valued based on their impact to HOL`s Corporate Strategic Objectives.

The Project Prioritization phase ranks each project based on their value. Resource constraints are used to create a detailed project list for HOL Executive Board approval.

The Project Execution phase uses HOL's Project Coach methodology to manage and execute the project plan. HOL's project coach is based on Project Management Institute best practices.

The Risk Assessment & Review phase measures progress on the Corporate Strategic Objectives, through the Asset Management Initiatives, and evaluates risk based on acceptable tolerances. This phase also captures feedback from the Project Execution phase to allow for continuous improvement and adjustments to the Asset Management Process such as lessons learned and increased forecast accuracy.

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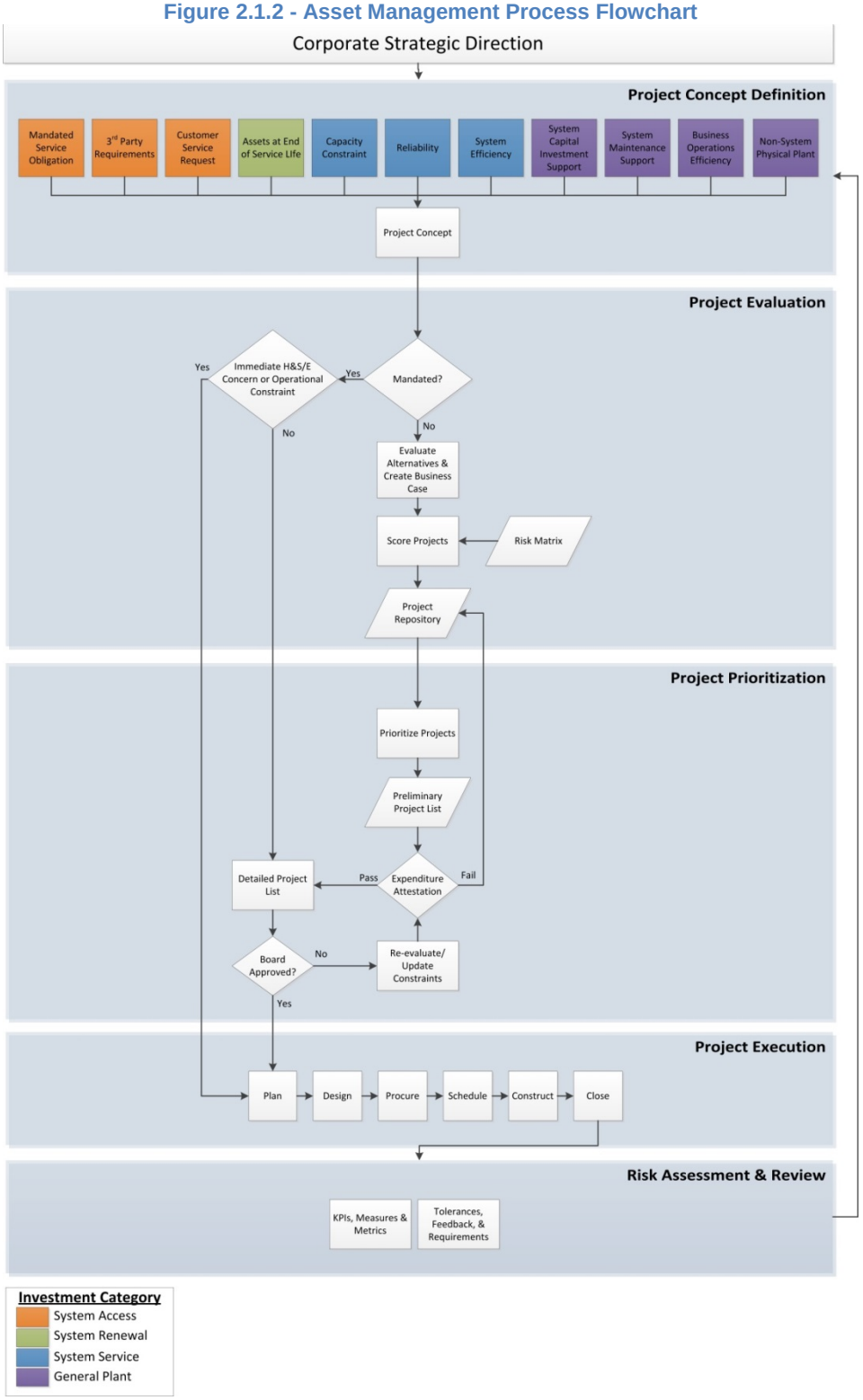
Figure 2.1.2 - Asset Management Process Flowchart



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2.1.2.1 Project Concept Definition

The Project Concept Definition phase gathers all internal and external drivers to describe the needs of our organizational environment. Concept projects are created to meet requirements, mitigate or remove risk, and reach Corporate Strategic Objectives. Table 2.1.1 outlines the description of the drivers by Investment Category, which are detailed in following sections.

Table 2.1.1 - Driver Descriptions

Investment Category	Driver	Description
System Access	Mandated Service Obligation	Regulatory requirement to maintain distribution licence under the OEB's Distribution System Code or requirement as per HOL's Conditions of Service
	3rd Party Requirements	Request by a 3rd party for plant relocation or upgrade to an existing service
	Customer Service Request	Customer request for new connection (load or generation)
System Renewal	Assets at End of Service Life i. Failure ii. Failure Risk iii. Substandard Performance iv. High Performance Risk	i. Asset no longer meets functional requirements ii. Asset is at risk to no longer meet functional requirements iii. Asset still meets functional requirements; however, falls below standards for operability or efficiency iv. Asset is at risk of failure in a way that can cause harm or damage to other equipment or assets or would put the distribution system in a detrimental state
System	Capacity Constraint	Requirement for additional capacity

Service		(station transformation or circuit) due to planned or realized load increases
	Reliability	Requirements driven by poor distribution system performance such as abnormally (high) duration or frequency of interruptions
	System Efficiency	Requirements for improved system operability and visibility
General Plant	System Capital Investment Support	• Capital contributions to Hydro One for connection projects • Requirement for fleet/vehicle acquisition
	System Maintenance Support	Requirement for tools and associated equipment
	Business Operations Efficiency	Requirements for Information Technology software and systems
	Non-System Physical Plant	Building infrastructure requirements

2.1.2.1.1 System Access

Mandated Service Obligations

Mandated Service Obligations are requirements of a distributor as defined by the OEB's Distribution System Code, as well as any additional obligations as defined by HOL's Conditions of Service. For example, providing metering and making repairs to damaged equipment to provide service to customers.

3rd Party Requirements

3rd Party Requirements are initiated from requests received for the relocation or upgrade (modifications) of assets or infrastructure. For example, pole relocation for road widening.

Customer Service Request

Customer Service Requests arise from the needs of load or generation customers for new connections. For example, servicing for new commercial buildings, residential subdivisions, or generators including any system expansion required to supply the site of development.

2.1.2.1.2 System Renewal

Assets at End of Service Life

HOL describes its asset replacement strategy, or asset management plan, in the Asset Management Planning Report (AMPR), contained within the Annual Planning Report (Attachment B-1(B)). The intention of the AMPR is to document the asset management practices used by HOL as part of an optimized lifecycle strategy for distribution and station assets and to document the Asset Condition Assessment (ACA). The objective of the ACA is to confirm that the assets deliver the required functions at the desired level of performance and that this level of performance is sustainable for the foreseeable future while staying within the targeted levels of risk.

The ACA is a key component of the asset management planning process. Addressed in the asset management plan are the financial, technical, and management elements needed for making sound, innovative or best practice asset management decisions.

The asset management plan looks ahead 20 years with a main focus on the first five years – for this period most of the planned projects have been identified. Beyond this period, analysis is less precise. Based on long term trends, current asset demographics, known asset issues or needs on the system, it is likely that new and planned projects will evolve in the latter half of the forecasted period.

The intent of the asset management plan is on optimizing the lifecycle costs for each network asset group (including creation, operation, maintenance, renewal and disposal) to meet reliability service targets and future demand. Each year, the aim is to improve the plan by taking advantage of new information and changing technology.

HOL's system assets range in age from new to over 50 years old. The management of these assets is critical to providing safe, reliable and efficient electricity distribution services to its customers.

The following list describes the key variables that are used to inform the Asset Condition Assessment as part of the asset management plan.

- Testing, inspection & maintenance records to inform condition;
- Asset demographic and nameplate information;
- Asset failure statistics – number of failures and frequency by asset type (SAIFI);
- Financial useful lives; and
- Financial records – cost per replacement.

The following list describes the results of the asset management planning process.

- Recommended asset replacement rates, refurbishment and associated annual spend;
- Asset condition (health index); and
- Projected failure rates based on spending/replacement levels.

2.1.2.1.3 System Service

Capacity Constraints

HOL routinely assesses the capability and reliability of the distribution system in an effort to maintain adequate and reliable supply to customers. Where gaps are found, appropriate plans for additions and upgrades which are consistent with all regulatory requirements for the connection of customers and with due consideration for safety, environment, finance and supply system reliability/security are developed. HOL summarizes the results of this capacity planning process in the Capacity Planning Report, contained within the Annual Planning Report (Attachment B-1(B)), in which the short and long term capacity needs for the service territory are identified.

In this regard, the supply needs in the service territory have been assessed to determine if additions and/or upgrades are required to maintain adequate and reliable/secure system capacity. HOL, being an amalgamation of 5 utilities, is composed of several subsystems which

are segregated by operating voltage and geographical boundaries. The capacity planning process reviews and summarizes the business case for each subsystem, identifying short and long term projects. Forecasted growth, asset replacement schedules, and reliability are all factors in planning the system.

The following describes the key variables that are used to inform the capacity planning process.

- Historical station transformer loading from the system wide annual peak day (weather normalized and adjusted to a one-in-ten year peak for forecasting);
- Historical feeder loading from the system wide annual peak day (weather normalized and adjusted to a one-in-ten year peak for forecasting);
- Station, station transformer and feeder planning capacity and ratings;
- Asset condition;
- System configuration and operating characteristics (and restrictions);
- Number of HOL customers;
- Historic energy purchased and delivered;
- Summer and winter peak load;
- City of Ottawa Official Plans and Community Development Plans;
- Land use designation and population and employment projections;
- Known developments through conversation with developers and City staff;
- Distributed generation connections and capacity;
- Station capacity to connect generation and plans in place to address any restrictions;
- Details and plans resulting from the Integrated Regional Resource Planning process with the IESO and Hydro One; and
- Details relating to Connection & Cost Recovery Agreements (CCRA) with Hydro One for station or transmissions projects

The following describes the results of the capacity planning process.

- One-in-ten year peak load forecasts (20 years) for each region/station;
- Need dates for capacity concerns; and

- Projects to address capacity needs (station upgrades, new stations, line extensions, transmission upgrades, voltage conversions);

Reliability

HOL continuously assesses the distribution system's service reliability. Where issues are found, the appropriate actions are identified to address these concerns. Service reliability is integral to all work undertaken as part of system planning and asset management. The reliability planning process is summarized in the Reliability Planning Report, contained within the Annual Planning Report (Attachment B-1(B)), and does not supersede the importance of good asset management and system capacity planning in the management of system reliability. Rather, it provides a platform for thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

Reliability driven projects are those which are designed to reduce outage frequency or duration regardless of the cause. Such initiatives are almost exclusively automation projects. In general, work considered as part of the system reliability plan are:

- Deployment of remote sensors;
- Deployment of remotely operable and autonomous devices;
- Deployment of field devices to provide fault indications locally;
- Supporting technologies to automation (i.e. communication & SCADA); and
- Modifications to existing standards (i.e. animal guards).

Successful lifecycle management of HOL's assets will have direct impact on system reliability – assets that are optimally maintained throughout their life, asset replacement prior to failure, and system planning to increase operability and reduce downtime.

The following describes the key variables that are used to inform the reliability planning process.

- Historical outage statistics (primary cause, secondary cause, duration, number of customers affected, circuit affected, station affected, date of interruption);
- Power quality measures (System Average RMS Frequency Index – voltage sags and swells); and
- Worst Feeder evaluation.

The following describes the results of the reliability planning process.

- Asset failure statistics – number of failures and frequency by asset type (SAIFI);
- Projects to improve the Worst Feeders reliability performance;
- Initiatives to improve overall reliability (specific to top 3 causes of interruption from the previous year); and
- Details on automation plans and how they will impact reliability.

System Efficiency

HOL's reliability planning process also reviews system efficiency, monitoring system losses and power quality. By maintaining voltage to CSA standards, customers can expect all of their devices, equipment and appliances to operate as intended and expected without damage or noticeable irritations such as dimming or flickering lights.

System Efficiency also comes from operating the system in an effective way. The SCADA system is key element for monitoring, controlling, and diagnosing HOL's network. It allows HOL's operators to quickly react to anomalies in the system by remotely operating devices or dispatching local crews to an accurate location.

2.1.2.1.4 General Plant

System Capital Investment Support

System Capital Investment Support captures the requirements for capital contributions to Hydro One for transmission connection projects as well as for HOL fleet acquisition.

System Maintenance Support

System Maintenance Support covers the requirements for tools and associated equipment used by HOL crews.

Business Operations Efficiency

Business Operations Efficiency is the requirement for Information Technology software and systems used to support daily business activities.

Non-System Physical Plant

Non-System Physical Plant captures the life cycle requirements for buildings.

2.1.2.2 Project Evaluation

The Project Evaluation phase defines project alternatives and creates business cases in support of the feasible alternatives. Unless mandated, project alternatives are evaluated and valued based on their impact to HOL`s Corporate Strategic Objectives.

Project concepts are first reviewed to determine if they are a mandatory project. Mandatory projects are typically dictated through the Distribution System Code or the Electricity Act. They range from customer connections, to line relocations, to restoring power in a timely fashion. Sometimes several alternatives are available to address a mandatory need in which case they are evaluated and one alternative is selected. These projects are then prioritized if they pose immediate concerns to health & safety, environment, or constrain the operation of the system. Immediate concerns move directly to the Execution phase and have the potential to take precedence over planned projects and cause deferral or delays. Otherwise, the projects make their way into the Detailed Project List, in the Investment Prioritization phase and are scheduled to be completed in an appropriate timely manner.

Non-mandated project concepts are reviewed and evaluated and possible alternatives are developed which will meet the desired objectives of the project. This evaluation is done through a business case development which clearly documents decisions.

Project alternatives are then scored by identifying their risk and/or benefit as it relates to HOL's Asset Management Initiatives through use of the Risk Matrix. The evaluation Consequence Matrix is shown in Table 2.1.2 which specifies the probability of an event occurring and the consequence of that event.

Event probability is specified either as a certainty or a variable associated with a state of a system element. The probability of an event is defined based on existing HOL process/evaluation or through sound engineering judgment. The key to the scoring process is that the probability is acknowledged to be variable in time (often increasing). To enable the development of a work plan, event probability reaching out to 20 years is required; with a 5 year window (i.e. probability is assessed for year 0, 5, 10, 15 and 20).

The consequence as it pertains to each measure is assessed on a linear scale. This scale covers the range of impact from *None* to *Severe* with an associated score of 0 to 6, respectively.

Each consequence has an associated weighting, see Figure 2.1.3, each having a dual function to normalize and to rank. While it is intended that the scoring scales between measures are normalized, the use of the weighting factors to assist in this is acceptable. Further, weighting is used to rank both the priority of a measure and its impact; a measure which has a relatively low impact on its associated initiative will also have a lower weighting. The sum of the weights of all the measures for a given Asset Management Objective must be equal to 1. The weighting of the measures is under the purview and approval of the Manager of Asset Planning.

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Table 2.1.2 - Asset Management Consequence Matrix (1/3)

Score	Level	Reliability & Customer Impact				
		System Reliability (SAIFI)	System Reliability (SAIDI)	System Reliability (FEMI)	Power Quality (Voltage)	Power Quality (Harmonics)
6	**Severe**	Will the project impact ≥ 5000 customers?	Will the project impact an area where restoration takes several days and may require additional resources?	Will this project impact feeder(s) within the upper decile of the FEMI score?	Will this project mitigate a customer investment of $5000 to rectify an issue?	Will this project mitigate a customer investment of $5000 to rectify an issue?
5	**Major**	Will the project impact ≥ 2500 customers?	Will the project impact an area where restoration takes up to 24 hours and will require all available crews?	Will this project impact feeder(s) within the upper quarter of the FEMI score?	Will this project mitigate a customer investment of ≤$5000 to rectify an issue?	Will this project mitigate a customer investment of ≤$5000 to rectify an issue?
4	**Significant**	Will the project impact ≥ 1000 customers?	Will the project impact an area where restoration takes up to 12 hours?	Will this project impact feeder(s) within the median and upper quarter of the FEMI score?	Will this project mitigate customer complaints and equipment damage?	Will this project mitigate customer complaints and equipment damage?
3	**Moderate**	Will the project impact ≥ 500 customers?	Will the project impact an area where restoration takes up to 8 hours?	Will this project impact feeder(s) within the lower quarter and median of the FEMI score?	Will this project mitigate customer complaints?	Will this project mitigate customer complaints?
2	**Minor**	Will the project impact ≥ 250 customers?	Will the project impact an area where restoration takes up to 6 hours?	Will this project impact feeder(s) within the lower quarter of the FEMI score?	Will this project mitigate customer complaints and voltages exceeding the standard levels defined in the Conditions of Service?	Will this project mitigate customer complaints and result in the generation of harmonics outside standard levels defined in the Conditions of Service?
1	**Minimal**	Will the project impact ≥ 100 customers?	Will the project impact an area where restoration will take up to 4 hours?	Will this project impact feeder(s) within the lower decile of the FEMI score?	Will this project mitigate voltages exceeding the standard levels defined in the Conditions of Service?	Will this project mitigate the generation of harmonics outside standard levels defined in the Conditions of Service?
0	**None**	Immaterial consequence or Not Applicable	Immaterial consequence or Not Applicable	Immaterial consequence or Not Applicable	Immaterial consequence or Not Applicable	Immaterial consequence or Not Applicable

Score	Level	Asset Management			
		Efficient Program Deployment	Asset Management (Asset Condition)	Asset Management (Asset Life)	Asset Capacity
6	**Severe**	Will the project eliminate an increase to O&M costs by >10% per year?	Will the project impact an asset that has failed?	Will the project impact an asset that will be required to operate beyond 50% of the useful life?	Will the project reduce the requirement of an asset to operate 20% beyond the rated capacity?
5	**Major**	Will the project eliminate an increase to O&M costs by ≤10% per year?	Will the project impact a Condition 5 asset?	Will the project impact an asset that will be required to operate beyond 35% of the useful life?	Will the project reduce the requirement of an asset to operate 17.5% beyond the rated capacity?
4	**Significant**	Will the project eliminate an increase to O&M costs by ≤8% per year?	Will the project impact a Condition 4 asset?	Will the project impact an asset that will be required to operate beyond 25% of the useful life?	Will the project reduce the requirement of an asset to operate 15% beyond the rated capacity?
3	**Moderate**	Will the project eliminate an increase to O&M costs by ≤6% per year?	Will the project impact a Condition 3 asset?	Will the project impact an asset that will be required to operate beyond 15% of the useful life?	Will the project reduce the requirement of an asset to operate 12.5% beyond the rated capacity?
2	**Minor**	Will the project eliminate an increase to O&M costs by ≤4% per year?	Will the project impact a Condition 2 asset?	Will the project impact an asset that will be required to operate beyond 10% of the useful life?	Will the project reduce the requirement of an asset to operate 10% beyond the rated capacity?
1	**Minimal**	Will the project eliminate an increase to O&M costs by ≤2% per year?	Will the project impact a Condition 1 asset?	Will the project impact an asset that will be required to operate beyond 5% of the useful life?	Will the project reduce the requirement of an asset to operate 5% beyond the rated capacity?
0	**None**	Immaterial consequence or Not Applicable	Immaterial consequence or Not Applicable	Immaterial consequence or Not Applicable	Immaterial consequence or Not Applicable

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Score	Level	Health & Safety		Environment
		Public Safety	Employee Safety	Oil Spills
6	Severe	Will the project mitigate the possibility of a severe injury? (permanent injury)	Will the project mitigate the possibility of a severe injury? (permanent injury)	Will the project mitigate the potential release of more than 2000L of oil?
5	Major	Will the project mitigate the possibility of a minor injury? (require hospital stay)	Will the project mitigate the possibility of a minor injury? (require hospital stay)	Will the project mitigate the potential release of 1000L to 2000L of oil?
4	Significant	Will the project mitigate the possibility of a significant injury? (require hospital visit)	Will the project mitigate the possibility of a significant injury? (require hospital visit)	Will the project mitigate the potential release of 200L to 1000L?
3	Moderate	Will the project mitigate the possibility of an injury? (short term medical leave)	Will the project mitigate the possibility of an injury? (short term medical leave)	Will the project mitigate the potential release of 100L to 200L of oil?
2	Minor	Will the project mitigate the possibility of a minor injury? (require first aid)	Will the project mitigate the possibility of a minor injury? (require first aid)	Will the project mitigate the potential release of 50L to 100L of oil?
1	Minimal	Will the project mitigate the possibility of a very minor injury? (bump, bruise, etc.)	Will the project mitigate the possibility of a very minor injury? (bump, bruise, etc.)	Will the project mitigate the potential release of less than 50L of oil?
0	None	Immaterial consequence or Not Applicable	Immaterial consequence or Not Applicable	Immaterial consequence or Not Applicable

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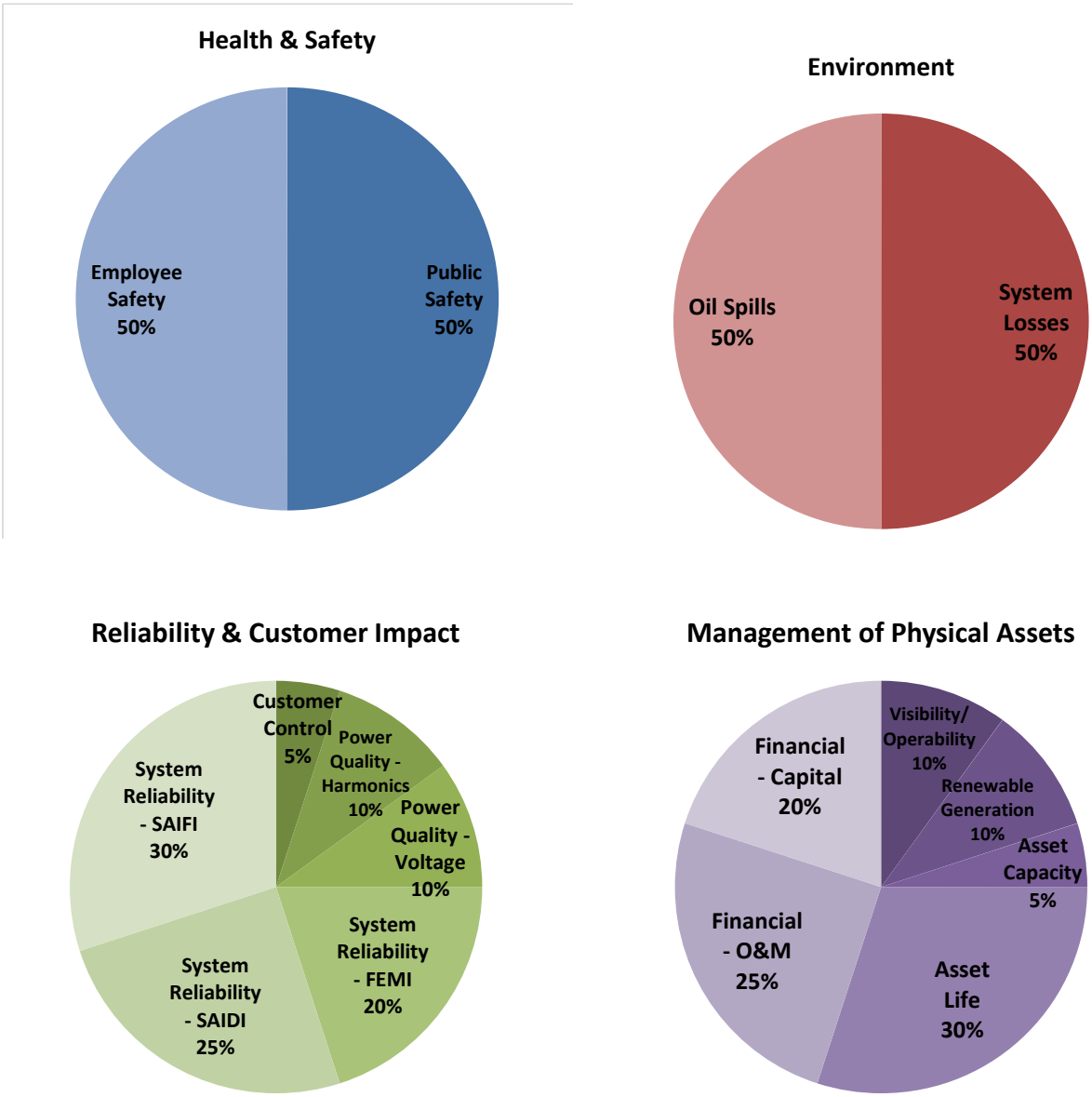
Figure 2.1.3 - Measure Weighting

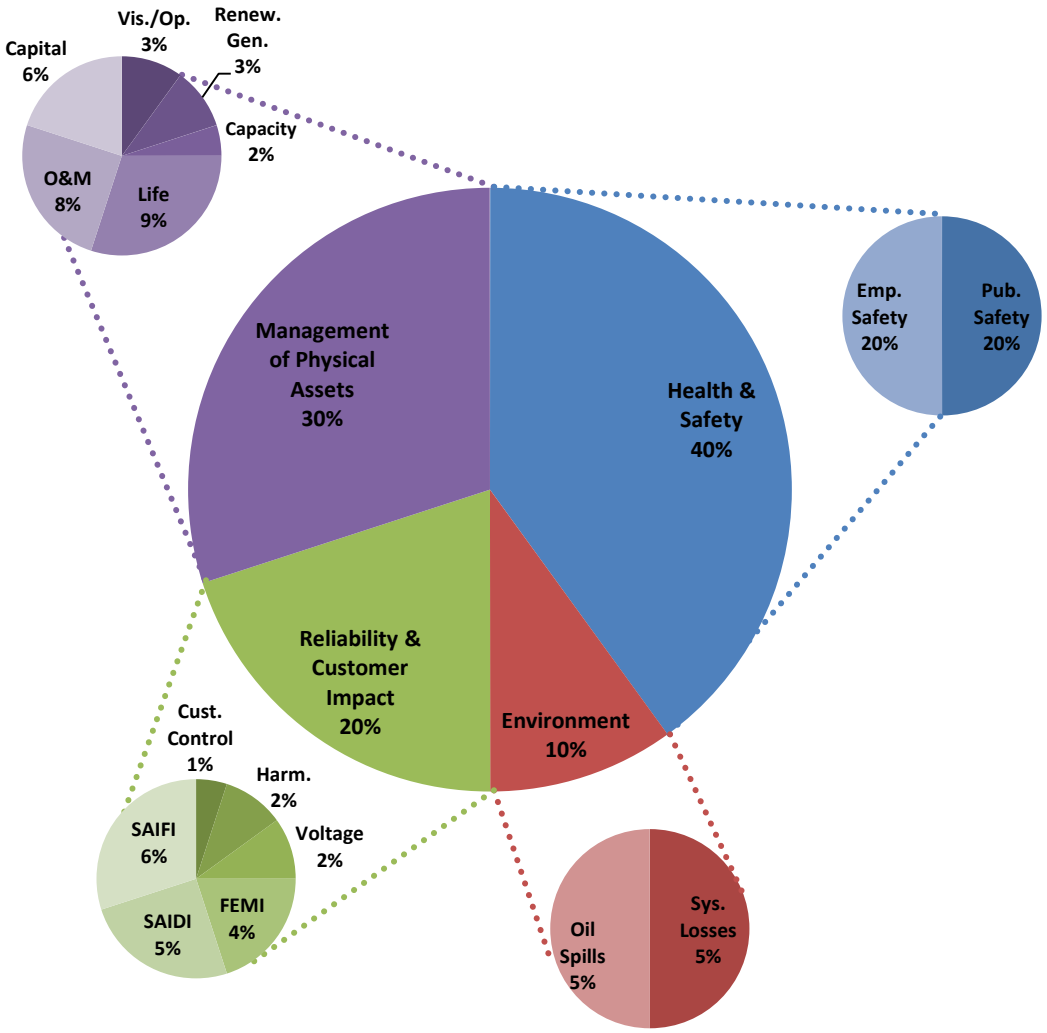


The risk associated with not undertaking an investment is calculated for each of the Asset Management Objectives first. Risk related for a given event is then calculated as the product of the event probability in a given year and the weighted sum of the associated consequences for each measure. Risk to the Asset Management Objective is calculated as the maximum risk, in a given year, of all of the associated events.

Each *Asset Management Objective* has an associated weight, which reflects the organizational prioritization of that objective and, as such, the associated weighting must be endorsed by the HOL Executive. The current objective weightings are summarized in Figure 2.1.4.

The Risk Score is a value which reflects a given overall investment's support of the Asset Management Objectives. This is calculated as the weighted sum of the risk for each Asset Management Objective in a given year. Although it is not quantified, Risk Score is considered to have an associated monetary value.

Figure 2.1.4 - Asset Management Objective Weightings



Once all projects have been scored on their risks and benefits, they are recorded in the Project Repository which contains all short and long term projects under consideration. This central location allows for all projects to be evaluated against one another and prioritized for planning.

2.1.2.3 Project Prioritization

The Project Prioritization phase ranks each project based on their value. All projects in the project repository are prioritized based on their risk score. This allows for all projects to be evaluated based on the same criteria to determine what projects will provide the most value

based on the Asset Management Initiatives. Investments are prioritized to maximize the value (i.e. risk score per dollar of investment). This cost/benefit ratio is calculated as the present value of the project cost (maximum 5 year window) over the 5 year present value of the project Risk Score. Investments are then prioritized based on ranking of this cost/benefit ratio. Projects with the lowest cost/benefit ratio are given higher priority over those with higher cost/benefit ratios.

A Preliminary Project List is created based on the prioritization process and expert knowledge of the needs and impact of the proposed projects. This list is attested against expenditure and resource constraints to create the Detailed Project List.

While it is preferred that the timing for all investments are based on this prioritization, mandated investments will arise, typically due to external drivers. When such investments occur they will have reasoning clearly documented and the impact to planned objectives will be reviewed.

The Detailed Project List of prioritized investments then moves on for approval from HOL's Executive Management Team and Board of Directors before proceeding to execution. This ensures that Corporate Strategic Objectives are being met through the proposed investment plan. Constraints may be re-evaluated and updated to meet objectives or mitigate risk.

2.1.2.4 Execution

The Execution phase follows an HOL internal project management methodology called "Project Coach" which defines the core lifecycle for projects. Project Coach is based on the internationally accepted standard for project management: Project Management Body of Knowledge (PMBOK) issued by the Project Management Institute.

Project Coach provides specific guidelines, procedures, work instructions and industry best practices that will allow Hydro Ottawa personnel to perform project work in an efficient, effective and high quality manner. Processes described in Project Coach are intended to be scalable and applicable to all projects, regardless of complexity and implements a consistent approach to planning, scheduling and execution of projects.

Project Coach describes 6 steps in the execution of the project:

1) **Planning & Project Initiation (Plan) –** The project charter, scope and objectives are created. Key players take steps to initiate the project and engage any needed authorization.
2) **Design –** The project charter, scope and objectives is reviewed and approved. Preliminary and detailed project design and estimates are created.
3) **Procurement & Circulation (Procure) –** The project design is approved. Material and services are procured.
4) **Scheduling (Schedule) –** The project is scheduled with key milestones and deliverable dates.
5) **Construction (Construct) –** The project is executed with a continuous review on progress and risk to completion.
6) **Closure (Close) –** The project documentation, financials, and reviewed lessons learned are completed. Feedback and lessons learned are registered and communicated for continuous improvement.

2.1.2.5 Risk Assessment & Review

The Risk Assessment & Review phase measures progress on the Corporate Strategic Objectives, through the Asset Management Initiatives, and evaluates risk based on acceptable tolerances. This phase captures feedback from the Project Execution phase to allow for continuous improvement and adjustments to the Asset Management Process.

The results of the Execution Phase are measures on operational performance which can be compared against baselines to identify trends. These measures are used to support the performance measurements identified in Section 1.3. The results are used to re-establish drivers by identifying what work was completed, if objectives have been met, and if there is still unacceptable risk that needs to be addressed.

2.2 Overview of Assets Managed

The overview of assets managed section of the DSP provides a summary of the features of HOL's distribution service area, demographics and condition of the assets managed. It also summarizes the current state of the system loading as it relates to station and feeder capacity.

2.2.1 Features of the Distribution Service Area

HOL was formed in November 2000 following the amalgamation of 5 municipal utilities of the former region of Ottawa-Carleton, and the restructuring of the Ontario electricity sector as a result of the Electricity Act, 1998. This has resulted in a diverse system with multiple service voltages and a variety of construction standards. HOL has worked hard since amalgamation to unite the former utilities with common processes and design standards.

HOL distributes electricity to 318,706 (October 2014) metered customers within the City of Ottawa and the Village of Casselman – an urban environment. See Figure 2.2.1 - HOL Service Territory for a map of HOL's service territory. The service area covers 1,104 square kilometers and is supplied by an even mix of overhead and underground feeders. In 2013, HOL purchased a total of 7,722 Gigawatt hours of electricity from the provincial grid to supply our customers. As the City grows, former rural areas fed by long distribution lines are becoming urban centres. This demands higher reliability expectations from customers.

HOL's service territory is additionally challenged by the natural barrier of the Rideau River and the Greenbelt which limits distribution connectivity in some areas of the system. As a result, system planning must consider these barriers when mapping out the distribution circuitry and evaluating capacity options.

Large segments of the system were constructed in the 1960s, 70s and 80s – as most assets have a lifespan on the order of 50 years, a considerable proportion of the system is approaching or has exceeded the anticipated end of life. The increased potential of failures posed by these aging assets will, without intervention, impact the organization's ability to guard worker and public safety, maintain system reliability and protect organizational strength in the future.

Overall, the City of Ottawa continues to grow in population and developed lands, primarily focused in five regions: the Downtown Core, Nepean & Riverside South, South Kanata &

Stittsville, the Village of Richmond and Orleans. The City has not seen any slowing of development as a result of the economic downturn and growth is expected to continue into the future. This growth is being seen through the development of new mixed commercial/residential communities**,** intensification of existing communities as well as major projects like the Ottawa Light Rail Transit (OLRT) system.

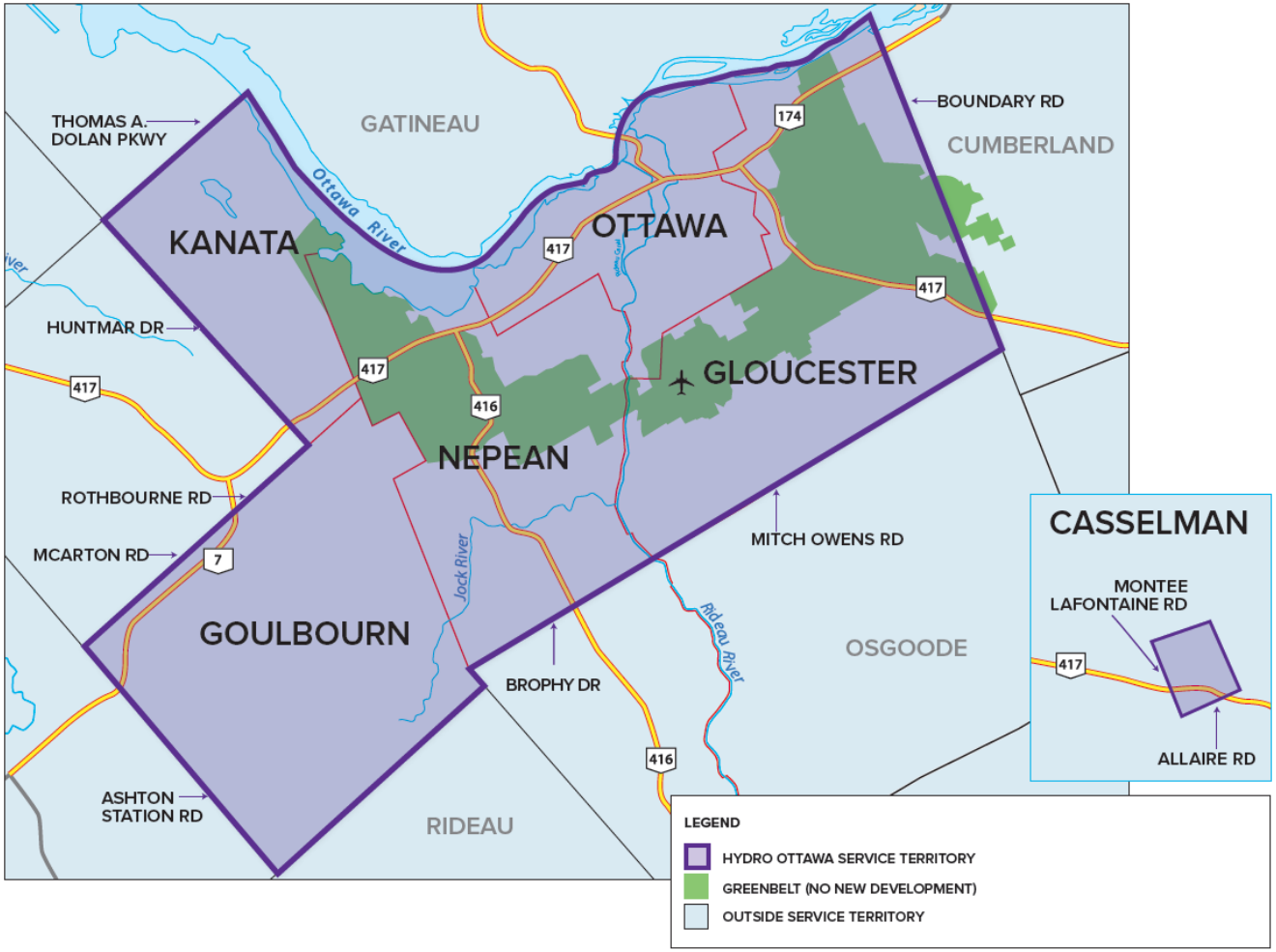
Table 2.2.1 - Conference Board of Canada Population and GDP Forecast

		2009	2010	2011	2012	2013	2014	2015	2016
Pop	('000)	1,237	1,258	1,277	1,295	1,311	1,322	1,333	1,346
	(%)	0.44%	0.40%	0.37%	0.33%	0.29%	0.20%	0.21%	0.27%
GDP	($M)	$60,424	$62,273	$63,028	$62,459	$62,870	$63,676	$65,036	$ 66,518
	(%)	0.55%	0.70%	0.36%	-0.16%	0.00%	0.41%	0.53%	0.57%

*Source: Conference Board of Canada, Ottawa-Gatineau Region

1

Figure 2.2.1 - HOL Service Territory



2

The following examples outline some of the issues that need to be addressed while planning the distribution system in Ottawa.

Climate Normals Comparison

In comparison to other major Ontario cities, Ottawa is characterized by having generally lower wind speeds and colder winters with higher snowfall (with the exception of Sudbury).

HOL strives to complete capital work year round; however, work must be scheduled to accommodate the winter months in which there are greater hazards to our crews and more challenges to overcome in the field, such as snow removal before work can even begin.

The data presented in the following charts represents the Climate Normals from 1981-2010 as recorded by the Government of Canada.

Figure 2.2.2 - Daily Maximum Temperature

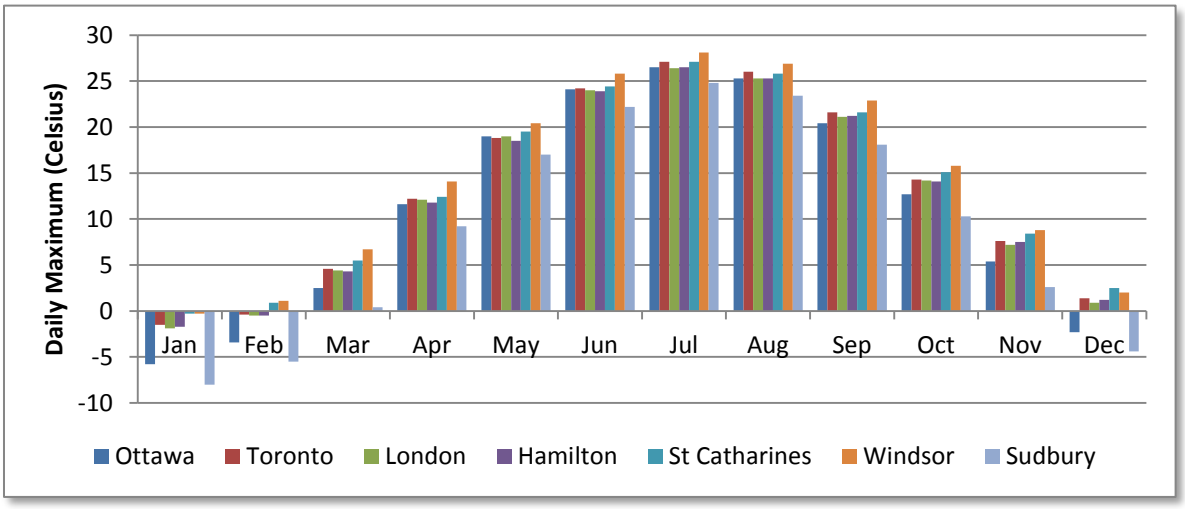


Figure 2.2.3 - Daily Minimum Temperature

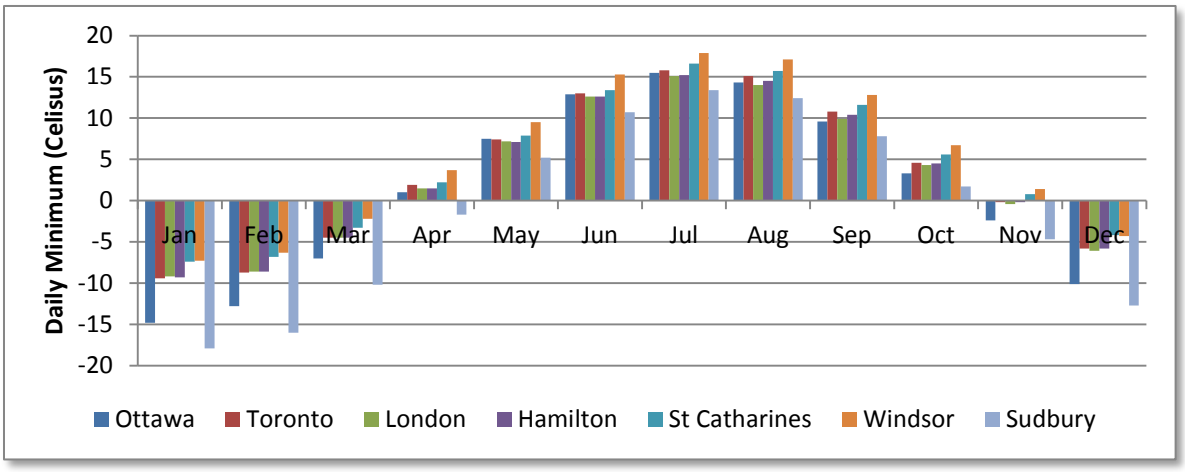


Figure 2.2.4 - Rainfall

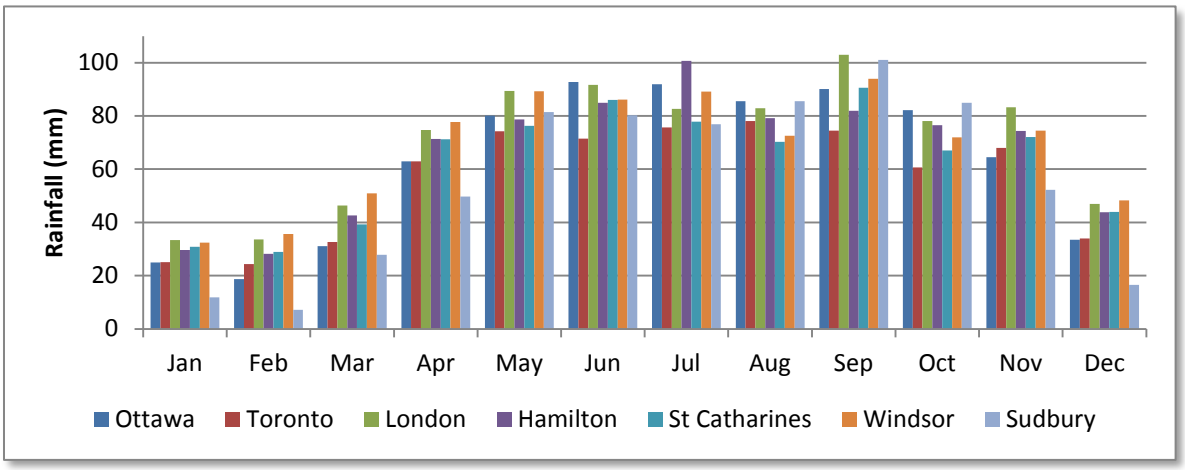


Figure 2.2.5 - Snowfall

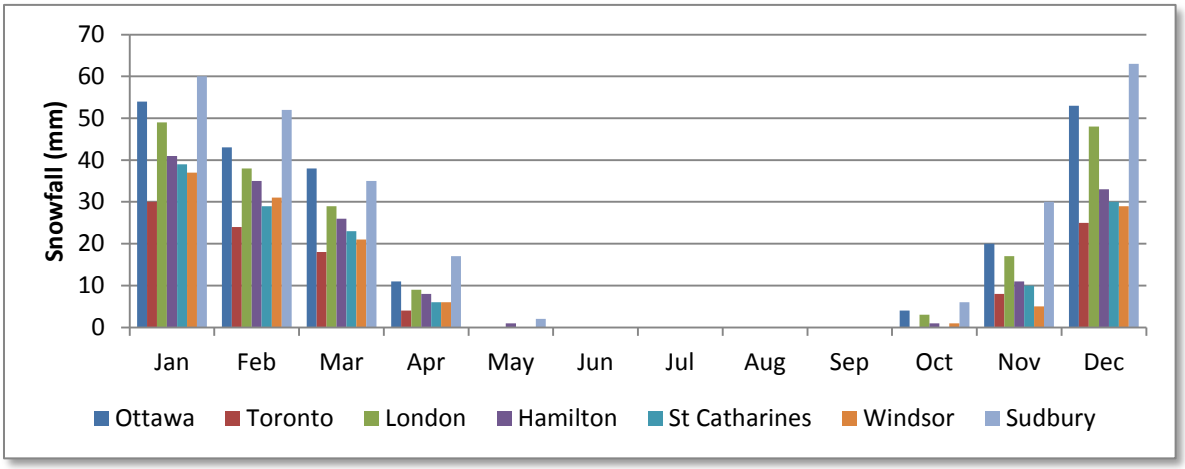
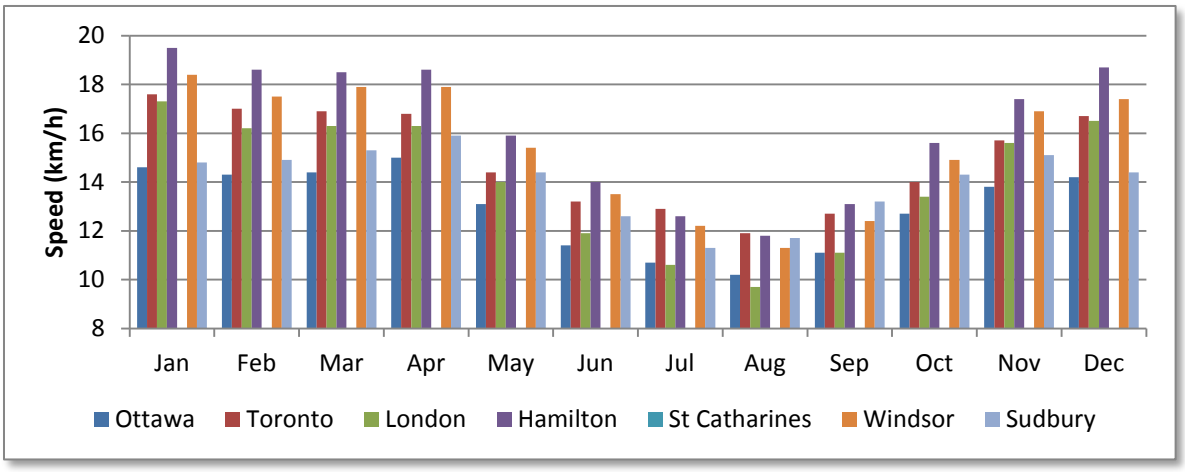


Figure 2.2.6 - Wind Speed



Temperature Profile

The Ottawa region temperature profile requires that equipment operate under a temperature range of -40 to +40 degrees centigrade. Various pieces of equipment that contain inert gasses may not operate reliably at the lower end of this range and thus require extra heaters to ensure reliable operation. Extra heaters on equipment causes design changes and non-standard equipment procurement. The requirement of additional heaters thus impacts capital investment and may require a larger initial investment than that of a similar equipment model in an area with a warmer temperature range.

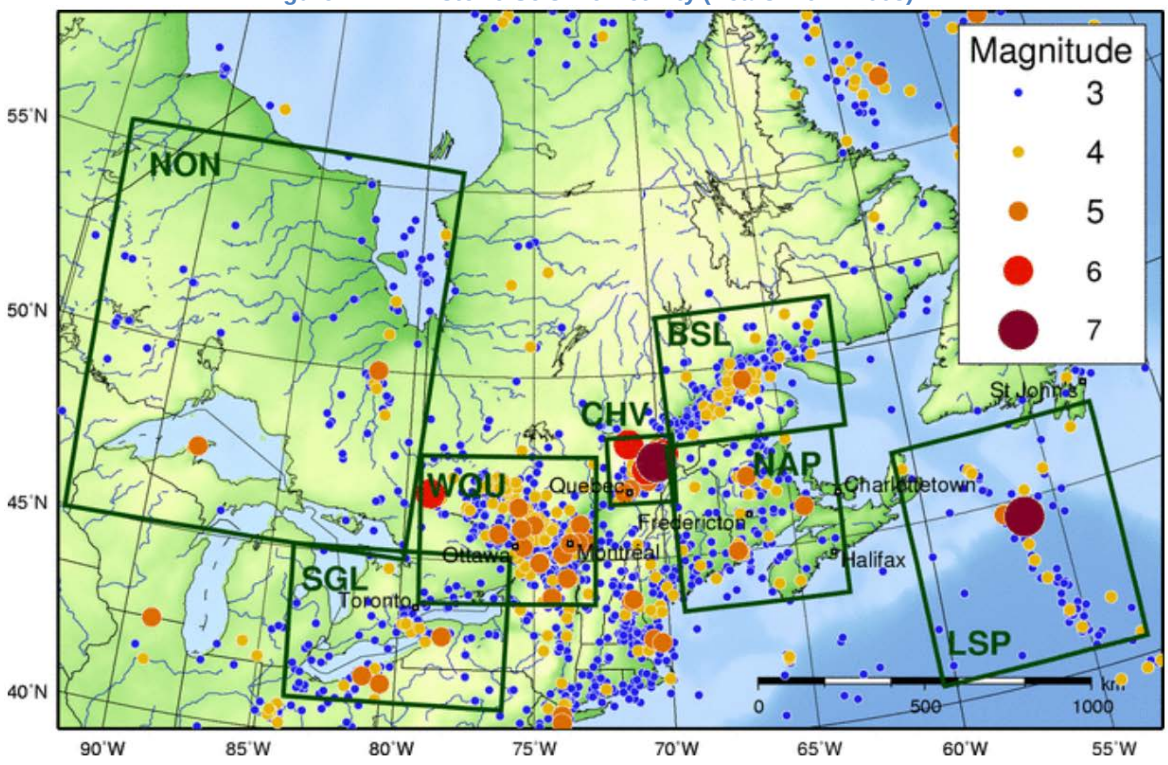
Seismic Zone

Ottawa sits within Zone 4 for Seismic Acceleration (0.16-0.23g) and Zone 2 for Seismic Velocity (0.0-0.11m/s). Ottawa sits within the Western Quebec seismic zone which sees on average one earthquake every five days (Natural Resources Canada).This requires civil footings and foundations to be designed and constructed to withstand these higher seismic levels. Larger foundations and footings means more reinforcing steel (rebar), larger excavations, and more concrete, contributing to increases in capital expenditures.

The seismic zone also requires that additional steel cross bracing is designed and installed on all structures. The additional bracing causes for larger design, fabrication, and installation costs than that of a zone of lower seismic activity.

Figure 2.2.7 depicts the historic level of seismic activity as recorded by the Canadian seismograph network and reported by the Government of Canada on Natural Resource Canada's website.

Figure 2.2.7 - Historic Seismic Activity (Years: 1627-2008)



**Source: Government of Canada, Natural Resources Canada*

Ice Accumulation & Snow Loading

Due to the amount of snowfall and ice accumulation experienced in Ottawa (see Figure 2.2.5), civil structures (structural steel) must be able to withstand a significant amount of ice build-up without impacting structural integrity. This requires that the specific alloys chosen must be of high quality and thus increases the cost of fabrication.

Another impact of the harsh winters is an increased use of road salt which can lead to premature rusting of padmounted and pole mounted equipment located along the road right of way. The salt spray from roadways impacts O&M costs by increasing the need to wash insulators to prevent arcing and flash overs which leads to asset failures as well as an increase in the need to repaint and repair rusted padmounted and pole mounted equipment.

Soil Conditions

The Ottawa area soil conditions generally fall within two categories: till soils with loam to sandy loam texture, and clay soils. There are also extensive bogs within the region consisting of pockets of moist to wet soils. In the west area of the City, soil materials are shallow and there are regions of exposed sedimentary bedrock.

The sandy and clay soil conditions call for increased civil infrastructure (piling) beneath the civil footings to ensure the stability of structures, specifically within substations. The piling necessitates further excavation, resources, material and design, and therefore higher costs. Due to the shallow bedrock there can be increases in costs associated with boring, for example with the installation of poles, ducts or piling to support civil structures.

2.2.2 System Configuration

HOL's diverse system comes from the amalgamation of the 5 former municipal utilities. The system has 6 different distributing voltages that are constructed in a mix of overhead and underground systems. The majority of the underground infrastructure is built in the downtown and integrated suburb areas.

The substations supplying the service area are a mix of HOL and Hydro One Networks Inc. (HONI) owned stations and transformers. Formally, HONI owned all transmission connected transformers supplying HOL owned breakers at the low voltage side to distribute electricity throughout the service area. The current practice for newly built transmission connected stations is for HOL to construct and own all equipment.

Below is a summary of the system configurations:

Table 2.2.2 - Length (km) of Underground & Overhead Systems

Orientation	Total Length (km)
Underground	2,782
Overhead	2,702
Total	5,484

Table 2.2.3 - Number & Length of Circuits by Voltage Level

Voltage Level	Number of Circuits	Total Overhead (km)	Total Underground (km)
4.16 kV	298	664	289
8.32 kV	112	717	504
12.43 kV & 13.2 kV	12 kV – 6 13 kV – 299	431	830
27.6 kV	52	720	1,152
44 kV	17	170	7
Total	784	2702	2782

Table 2.2.4 - Number & Capacity of Transformer Stations

Secondary Voltage Level	# of Station	# of Transformers Owned by HOL	# of Transformers Owned by HONI	Total Transformation (MVA)
4.16 kV	36	103	0	662
8.32 kV	24	39	3	448
12.43 kV	2	3	0	26
13.2 kV	12	2	25	1776
27.6 kV	14	21	4	843
44 kV	3	0	6	416
Total	91	168	38	4170

*Note that this is a sum of top rating (not planning limit) of all in-service units in HOL's service territory

2.2.3 Asset Demographics and Condition

The following section summarizes the demographics and condition assessment for the major asset classes within HOL's system. Asset condition is based upon health index calculations which are unique for each asset class. Where information is lacking, a correlation is implied between condition and age. Further details on the asset demographics can be found in the AMPR.

Table 2.2.5 summarizes the condition and population statistics for the asset classes that are detailed in the following sections. All information is current as of the end of 2013. Note that the cable lengths in the table below represent total kilometers of installed cable (sum of each run of cable, i.e. 3x for three-phase circuits) and differs from the stats provided above which represent circuit kilometers (1x for three-phase circuits).

Table 2.2.5 - Asset Demographics & Condition

Asset Type	Population	Average Age	% in Poor & Critical Condition
Poles	59,450	39	12%
Polemounted Transformers	15,663	30	11%
Kiosk & Padmounted Transformers	15,633	33	4%
Vault Transformers	3,474	34	7%
Distribution Cables (XLPE)	4,128 km	25	17%
Distribution Cables (PILC)	356 km	35	15%
Underground Switchgear	439	15	2%
Station Transformers	170	36	2%
Station Breakers	1,003	36	5%

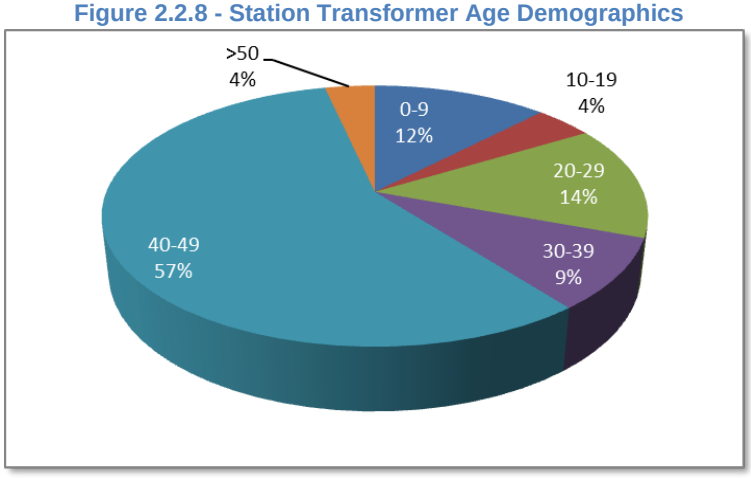
Table 2.2.6 - Asset Management Strategy

Type	Asset	Strategy	Age / Condition Based Replacement
Substation	Transformers	Proactive	Condition
	Switchgear	Proactive	Condition
	Batteries	Proactive	Age
Distribution	Overhead Conductor	Proactively replaced with other projects	N/A
	Poles	Proactive	Condition
	Cable – PILC	Reactive	N/A
	Cable – XLPE	Proactive/Refurbish	Condition
	Cable – Butyl Rubber	Proactive	Condition
	Cable – EPR	Reactive	N/A
	Padmounted & Kiosk Transformers	Reactive	N/A
	Polemounted Transformers	Reactive	N/A
	Vault Transformers	Reactive	N/A
	Underground Switchgear	Proactive	Age
	Underground Civil Structures	Proactive	Condition
	Overhead Distribution Switches and Reclosers	Reactive	N/A

2.2.3.1 Station Transformers

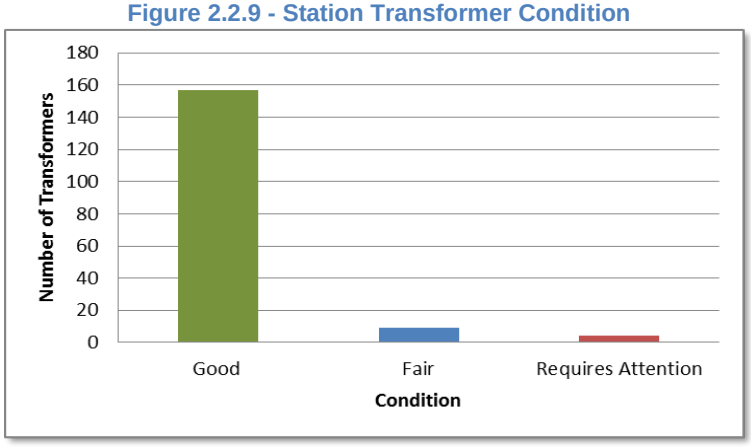
Station transformers are critical pieces of equipment among HOL's groups of assets. They provide voltage transformation from high voltage transmission lines to a lower voltage to distribute electricity throughout the City. HOL has 170 station transformers with different primary voltages: 103 at 13.2kV, 39 at 44kV, 22 at 115kV and 6 at 230kV.

Figure 2.2.8 - Station Transformer Age Demographics



HOL currently tracks the health index of Station Transformers through results from dissolved gas analysis (DGA), oil quality analysis and Doble testing. These various quality tests allow HOL to monitor the concentration of the Key Gases, the rate at which these gases are increasing, and the quality of the mineral oil inside the transformer. Once the gases, rate of change, and oil quality have reached an unacceptable level, the transformer will be scheduled for an out-of-service inspection and potential refurbishment or replacement.

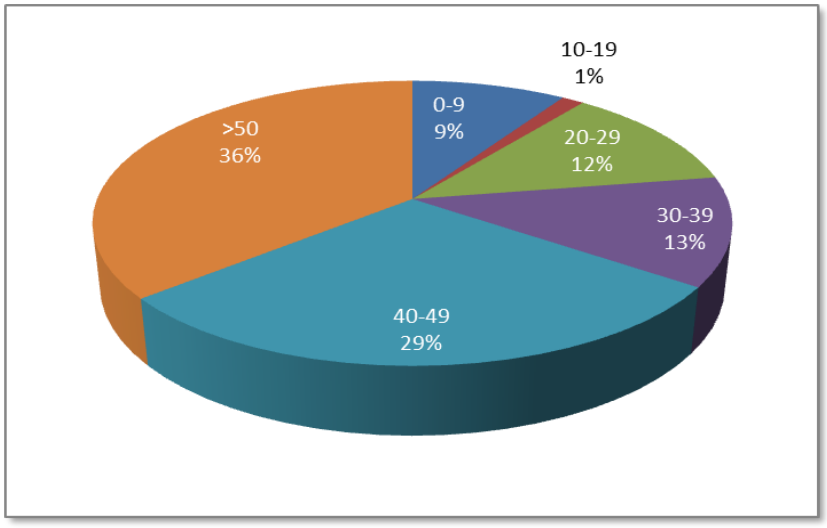
Figure 2.2.9 - Station Transformer Condition



2.2.3.2 Station Switchgear

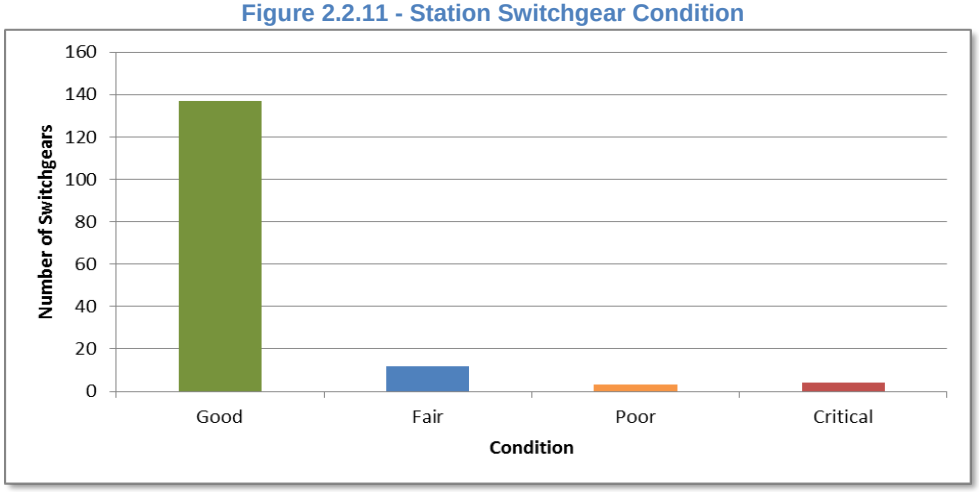
HOL owns and maintains switchgear assemblies in 83 substations. The station switchgear asset class consists of breakers, switches, bus insulation, support structures, protection and control systems, arrestors, control wiring, ventilation and fuses.

Figure 2.2.10 - Station Switchgear Age Demographics



The health index for Station Switchgear takes into account the many functional and supporting parts. A qualitative assessment of the equipment condition, based on subject matter experience, is done on the switches, breakers, bus, insulation, and supporting structures. The equipment is then reviewed for functional obsolesce and the availability of spare parts. The health index is calculated using this information and the age of the equipment.

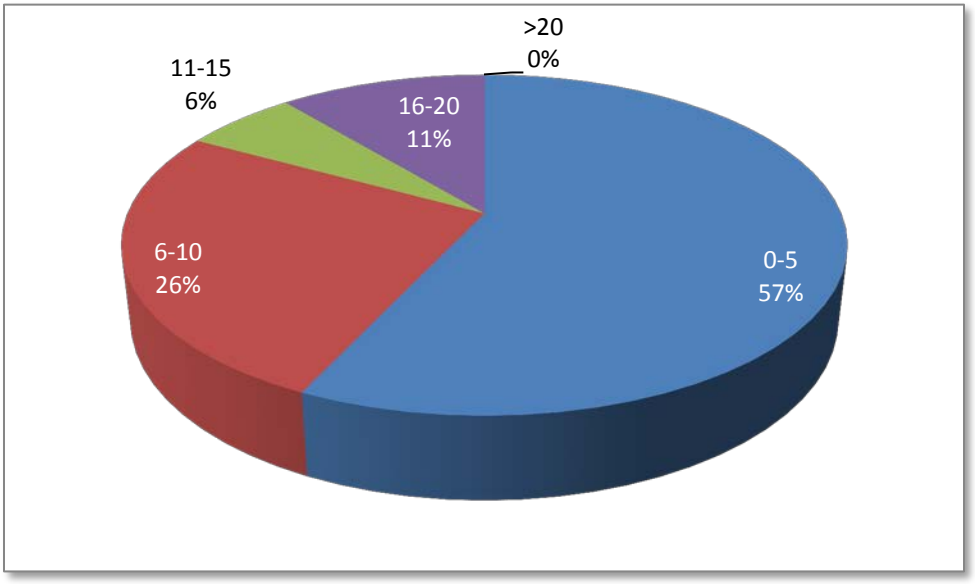
Figure 2.2.11 - Station Switchgear Condition



2.2.3.3 Station Batteries

HOL's station batteries and chargers asset class provide power for operating station breaker trip and closing coils, DC lights and relays when the station service power is lost. HOL has 53 station battery banks that supply 24V, 48V and 125V. The life expectancy of a station battery bank is in the range of 20-25 years.

Figure 2.2.12 - Station Battery Bank Age Demographics



The condition of station batteries is assessed through regular inspections. Routine maintenance is also performed which enables their health to be closely related to their age. The failure consequence for this asset can be significant as all the controls in a substation rely on the DC system to operate in case of power interruption. For this reason HOL replaces 2-3 station battery and charger banks per year to ensure reliable operation.

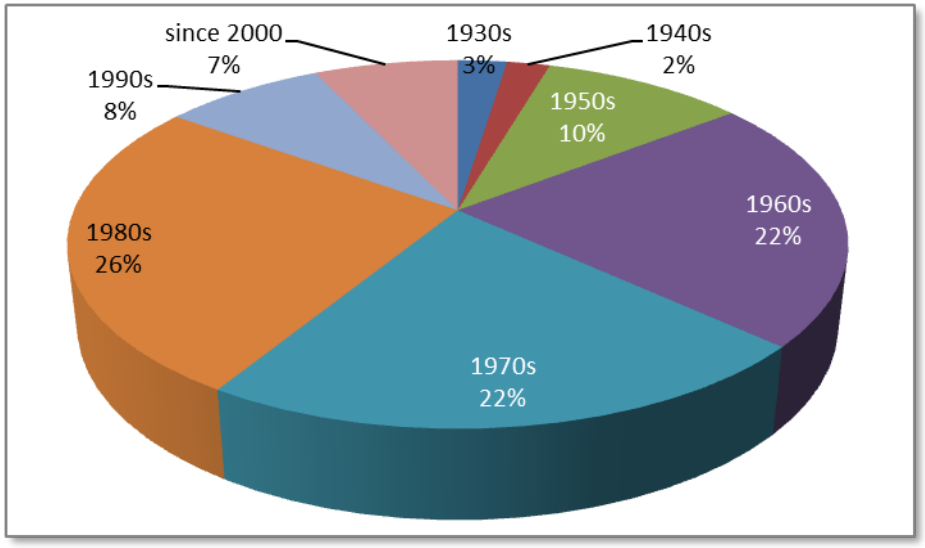
2.2.3.4 Overhead Conductor

HOL owns and operates on over 2900km of overhead conductor. Due to the rarity of overhead conductor failures, HOL does not record or perform inspections. The conductors are replaced during work on pole top equipment or pole replacement projects. This allows for the greatest efficiency. During this time the area is studied to assess whether larger conductors need to be installed.

2.2.3.5 Distribution Poles

HOL owns 47,815 wood poles and 537 non-wood poles and operates on an additional 11,635 wood and 126 non-wood poles which are owned by third parties. Currently, HOL has installation date information for approximately 25% of its poles (41% of those operated on). For poles that do not have available installation information, install data has been estimated using manufacture date, estimated from the adjacent property legal records, or assumed to be equivalent to the average age of the known poles in that region (roughly 41% of asset group).

Figure 2.2.13 - Distribution Pole Age Demographics



The condition of poles is evaluated against a health index developed by HOL. The health index for poles is based on determining the percentage of remaining strength left in the pole. As per Canadian Electrical Code - CSA 22.3, poles should be replaced once they fall below 60% of the required strength. HOL uses the CSA criteria that once a pole's ultimate strength has been reduced to 60% of its original design, it will be considered to be at end of life and scheduled for replacement.

Health Index Inputs:

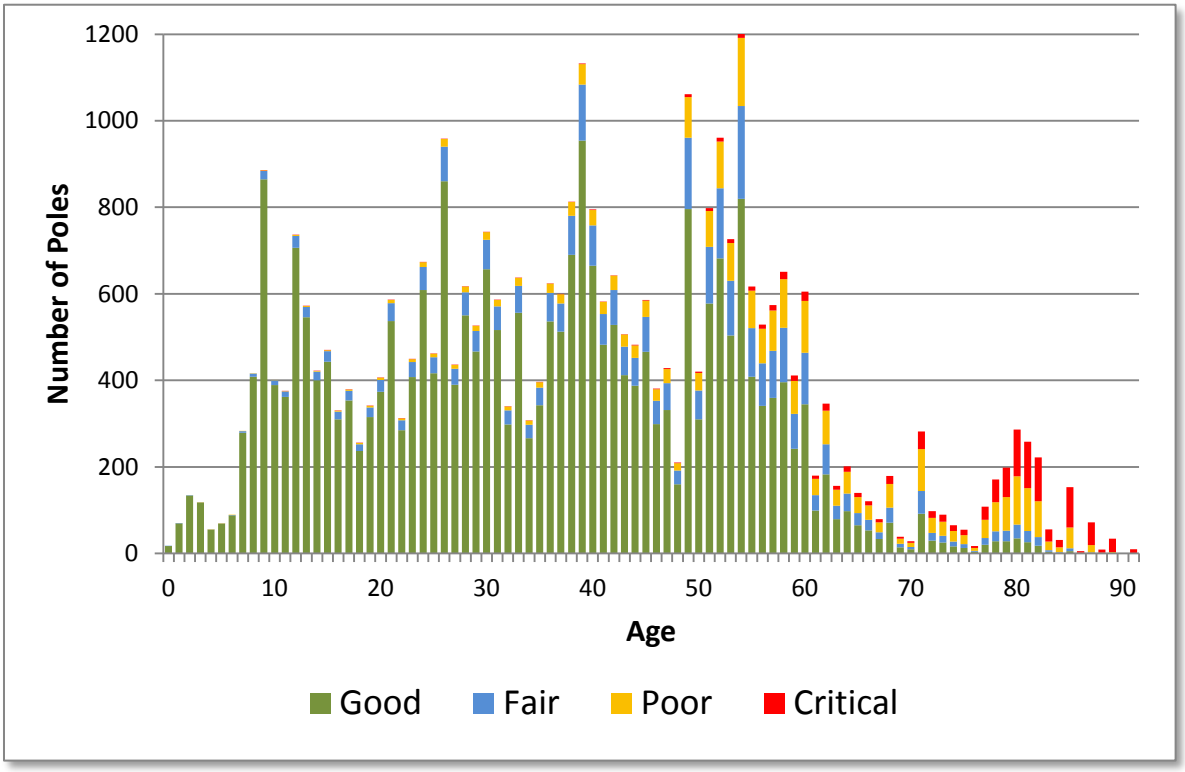
1. Maximum and minimum ground line circumference to determine the extent of surface rot and mechanical damage due to vehicles and snow plows;
2. Width and depth of pocket holes along the pole caused by rot or woodpeckers; and

3. Width of the external shell of a pole, measured from the center, which can be reduced due to internal rot.

HOL has inspected 14,370 poles since 2011, an average of 3,592 poles per year with a continued program inspection target of 4,500 poles per year over a ten year cycle. These inspections are initially done visually and if a pole appears to be in a degraded state a drill test is completed. As mentioned above, if the pole is determined to have a remaining strength below 60% it is replaced. When an area is identified as having numerous poles in a degraded state a pole replacement project is initiated.

Currently, HOL is working to prioritize and replace poles with a known condition of critical or poor from the 14,370 completed inspections, with an intention to continue to the inspection process and continue to replace poles based on the inspection results. Although not all poles have yet been inspected, the information already collected (shown in Figure 2.2.14 below) has been used to project the condition over the population of remaining poles.

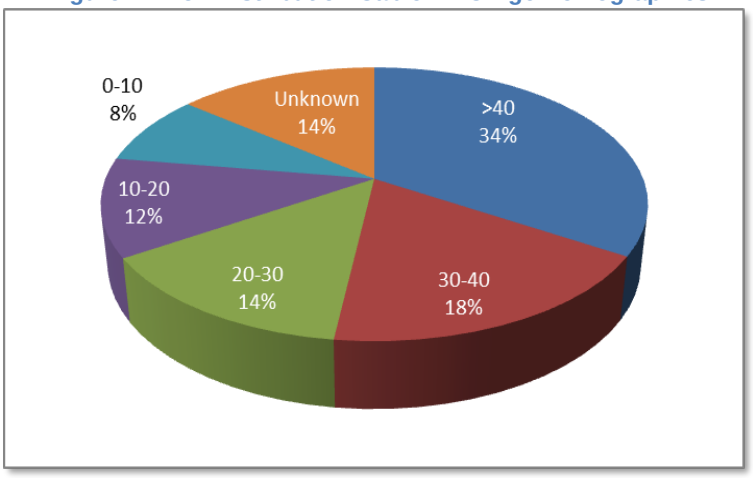
Figure 2.2.14 - Distribution Pole Condition



2.2.3.6 Distribution Cables (PILC)

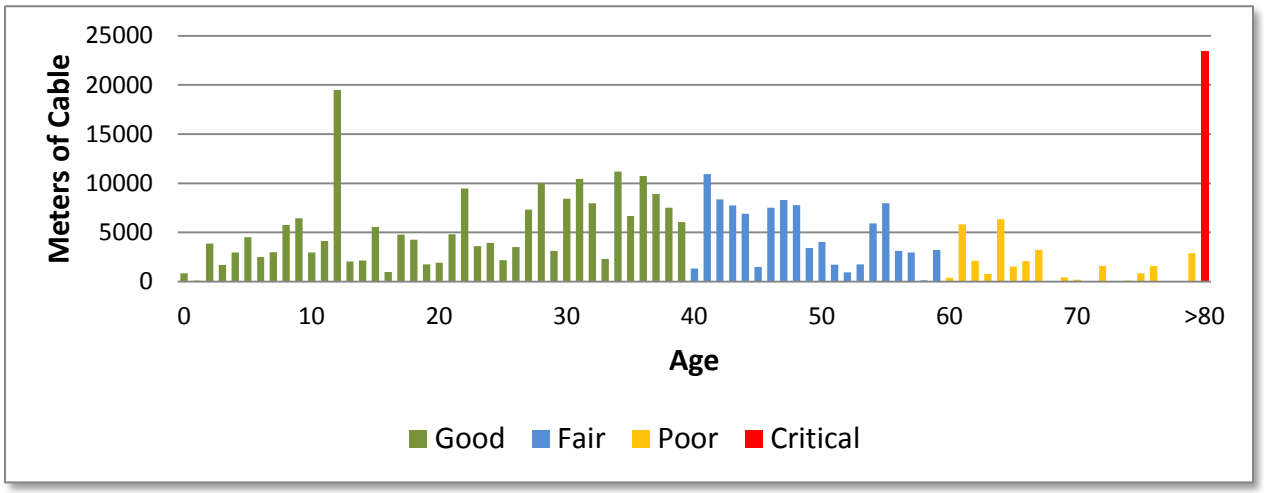
HOL owns and operates 356 km of triple conductor Paper Insulated Lead Cable (PILC). It was primarily installed in the Core of Ottawa on the 13kV system and is some of the oldest cable in the service area. Due to higher material costs, increasing procurement lead times, and the need for specialised tradesmen, HOL is passively phasing out this cable type by installing alternative cable types for new installations.

Figure 2.2.15 - Distribution Cable PILC Age Demographics



The condition assessment for PILC cables is based on age alone. Critical and poor condition cables are considered to be over the ages of 80 (Weibull Analysis) and 60 (Historical Failures), respectively. These assets are considered to be at a higher risk of failure.

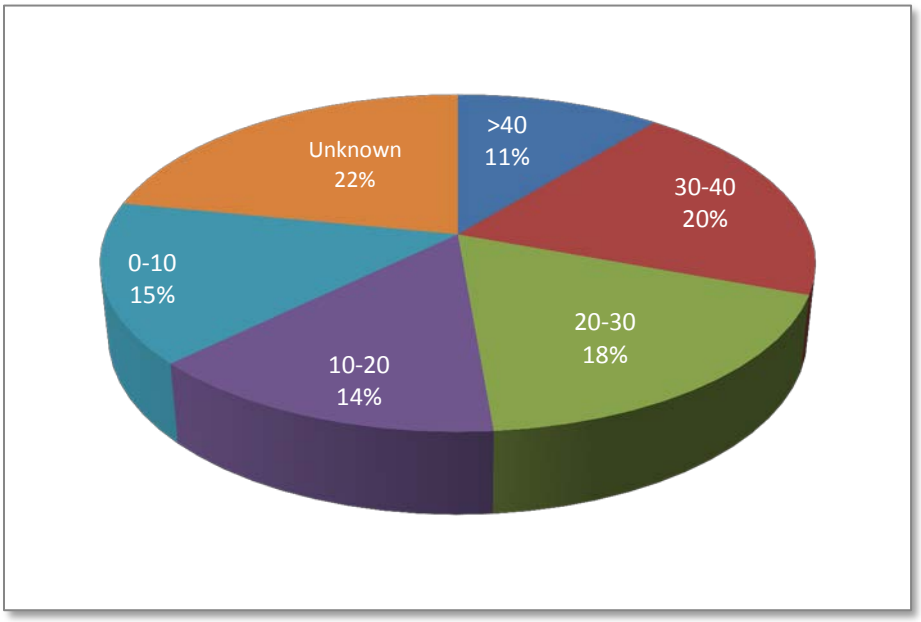
Figure 2.2.16 - Distribution Cable PILC Condition



2.2.3.7 Distribution Cables (Polymer)

HOL owns and operates 4,128 km of single conductor Polymer Cable (Cross-Linked Polyethylene (XLPE), Ethylene Propylene Rubber (EPR) and Butyl Rubber) which is primarily installed in developed suburbs. The installation of this cable uses a mix of concrete encased duct, direct buried duct, and direct buried cable which can add to the cost and labour requirements when replacing under planned and unplanned events.

Figure 2.2.17 - Distribution Polymer Cable Age Demographics



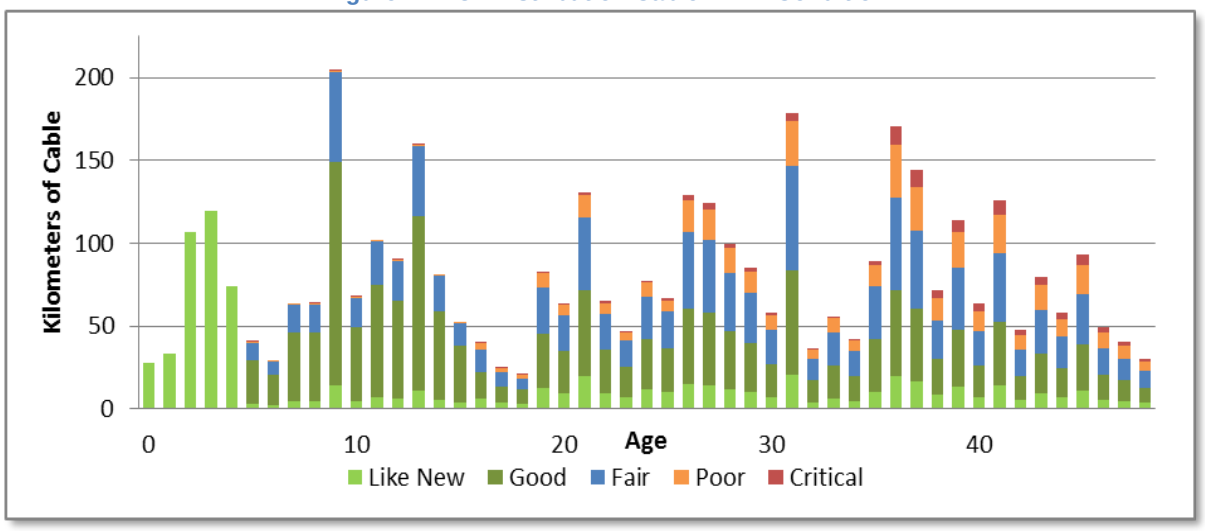
The vast majority of the underground polymer cable is XLPE. Butyl Rubber is in the process of being phased out of HOL's system due to the number of failures. EPR has been newly introduced into the HOL system and only makes up a small portion of underground cable. Therefore, the condition of underground polymer cable uses data collected from tests on XLPE cable.

The condition of distribution XLPE cables are monitored through an underground cable testing program which collects information useful for developing an asset health index. The health index for XLPE is based on the remaining insulation strength of the cable. The tests done on XLPE provide a Quality (Q) Value which indicate the condition of the cable. HOL uses the

criteria that once the Q Value reaches a value of 32 or greater, it is considered to in either Bad or Critical condition and should be scheduled for replacement.

The entirety of the XLPE cable population within the HOL system has not yet been tested, however a correlation of the current findings are represented across the entire demographics in the figure below.

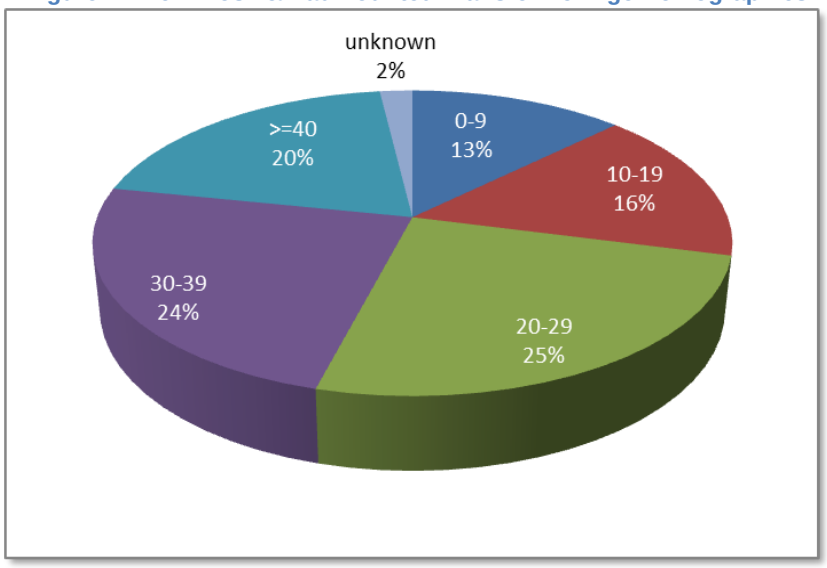
Figure 2.2.18 - Distribution Cable XLPE Condition



2.2.3.8 Kiosk & Padmounted Transformers

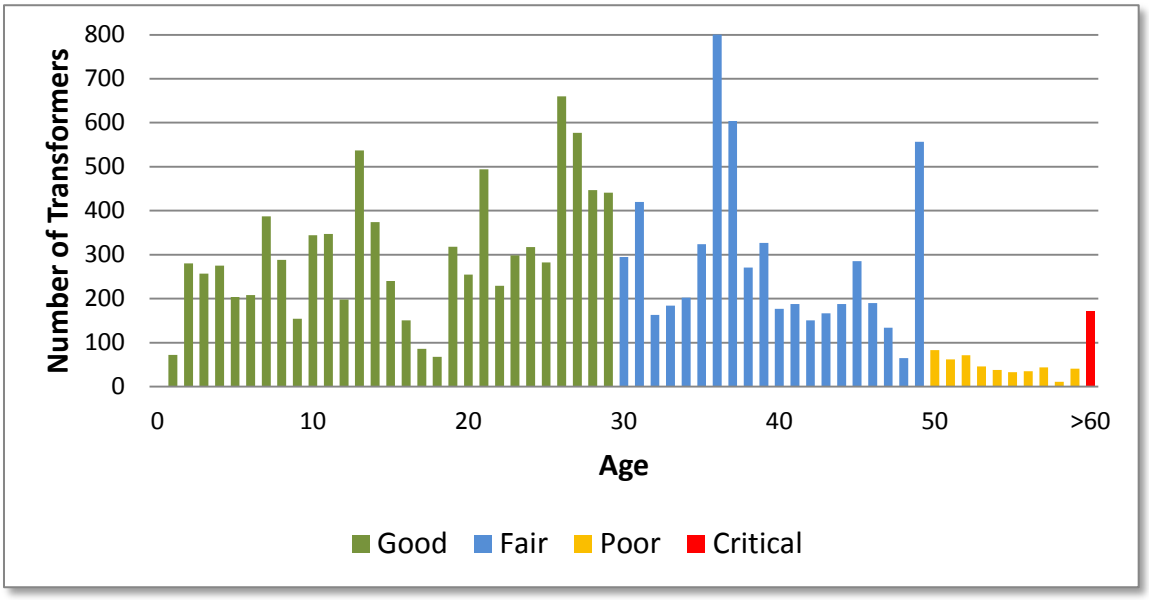
HOL owns roughly 1,800 kiosk transformers and 14,000 padmounted transformers. Kiosk style transformers have been in use for longer than padmounted transformers and as a result there is a higher proportion of this style at end of life.

Figure 2.2.19 - Kiosk & Padmounted Transformer Age Demographics



The condition assessment for padmounted transformers is based on age alone. Critical and poor condition transformers are considered to be over the ages of 60 (Weibull Analysis) and 50 (Historical Failures), respectively. These assets are considered to be at a higher risk of failure.

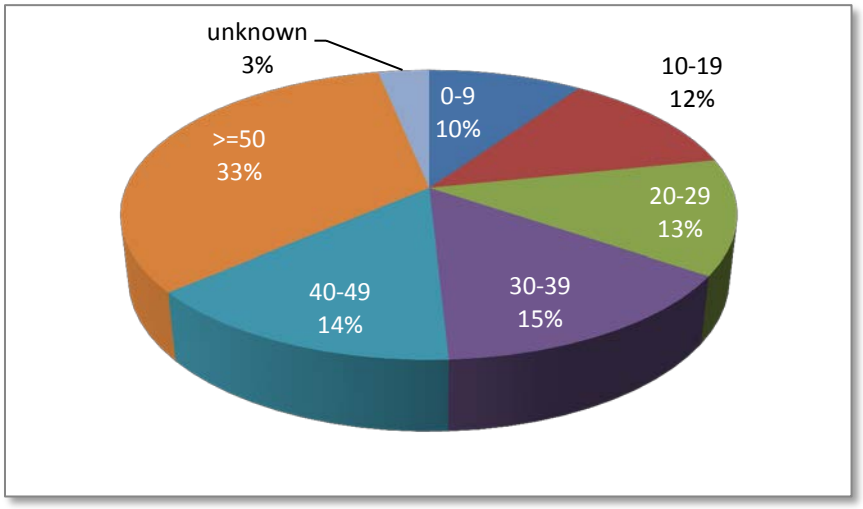
Figure 2.2.20 - Kiosk & Padmounted Transformer Condition



2.2.3.9 Polemounted Transformers

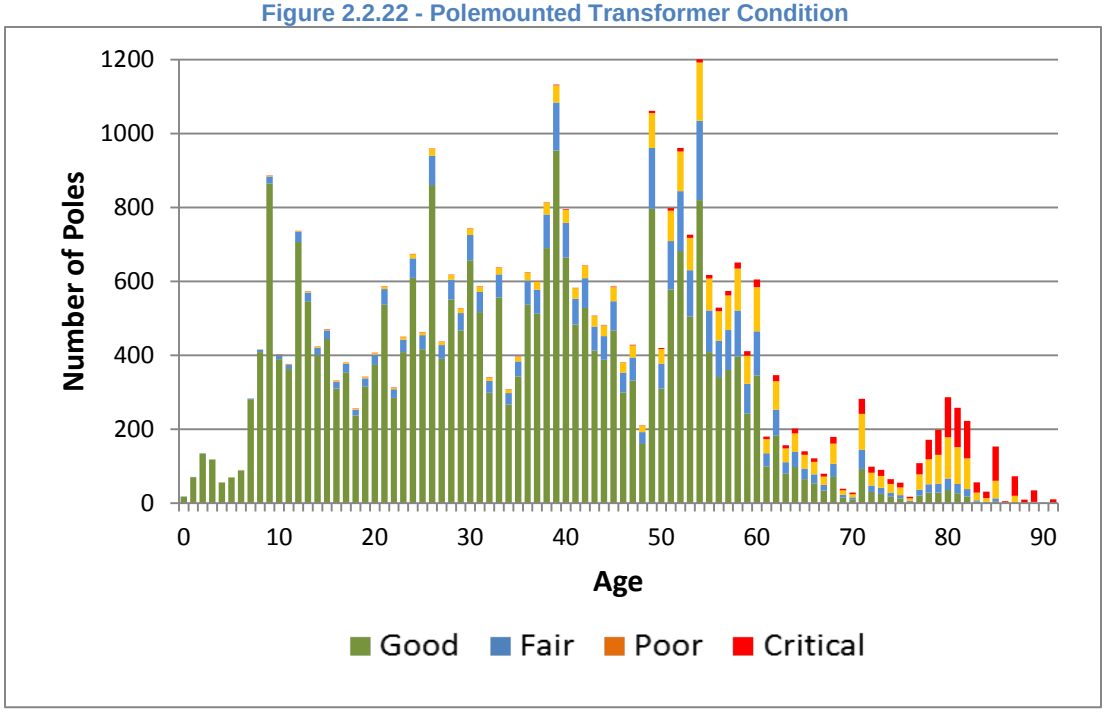
Demographic information for polemounted transformer assets such as purchase date, manufacture date, ratings and manufacturer are stored in HOL's Geographical Information system (GIS). HOL owns and operates 15,663 polemounted transformers. Currently, the installation and manufacture date are not consistently available. As such, where install year is not available it has been approximated based on the purchase year, estimated install year, or based on legal documentation of the surrounding properties.

Figure 2.2.21 - Polemounted Transformer Age Demographics



The condition assessment for polemounted transformers is based on age alone. Critical and poor condition transformers are considered to be over the ages of 90 (Weibull Analysis) and 60 (Historical Failures), respectively. These assets are considered to be at a higher risk of failure.

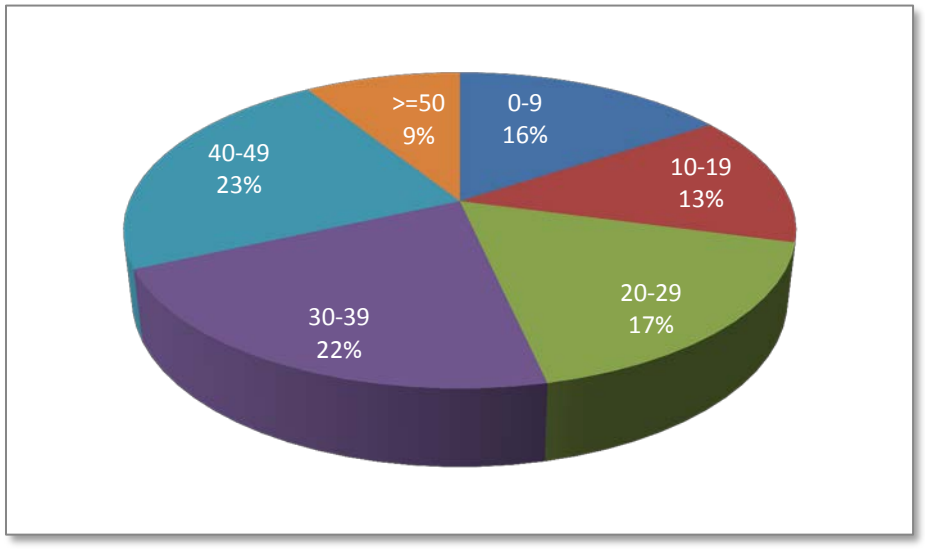
Figure 2.2.22 - Polemounted Transformer Condition



2.2.3.10 Vault Transformers

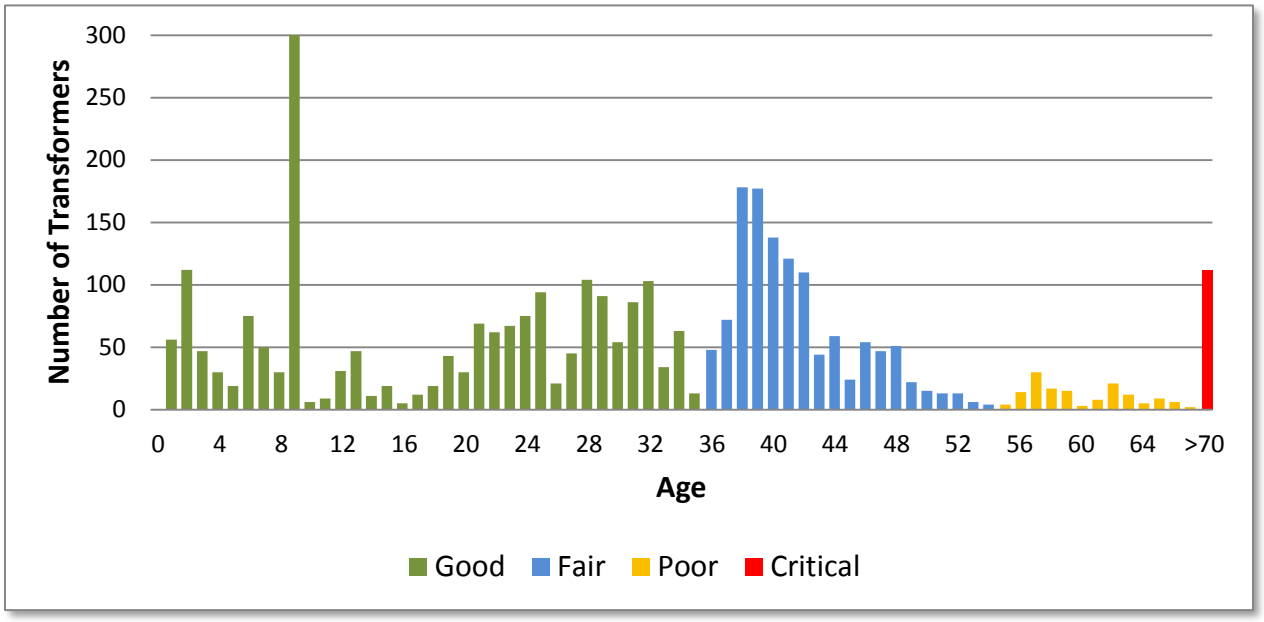
HOL's vault transformers are located in building vaults and typically service a single large customer. Currently HOL owns 3,474 vault transformers.

Figure 2.2.23 - Vault Transformer Age Demographics



The condition assessment for vault transformers is based on age alone. Critical and poor condition transformers are considered to be over the ages of 70 (Weibull Analysis) and 65 (Historical Failures), respectively. These assets are considered to be at a higher risk of failure.

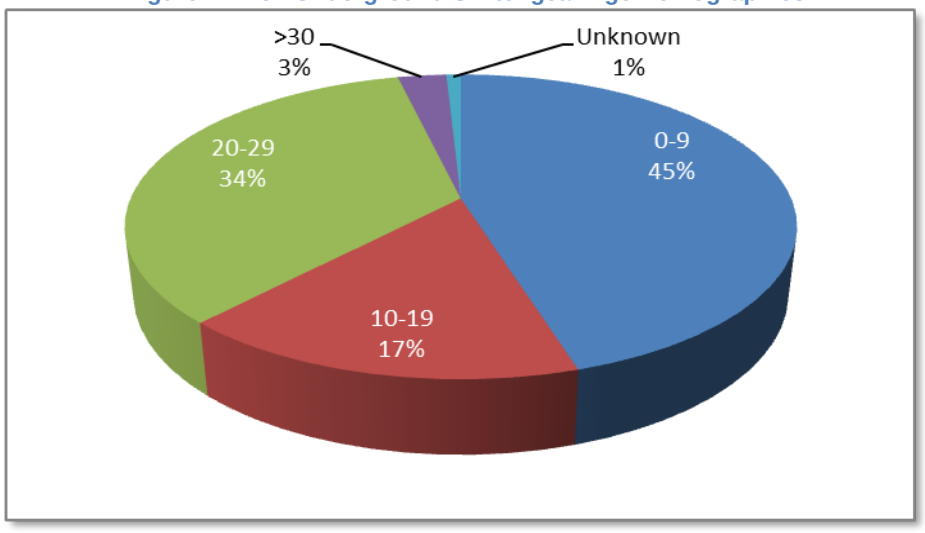
Figure 2.2.24 - Vault Transformer Condition



2.2.3.11 Underground Switchgear

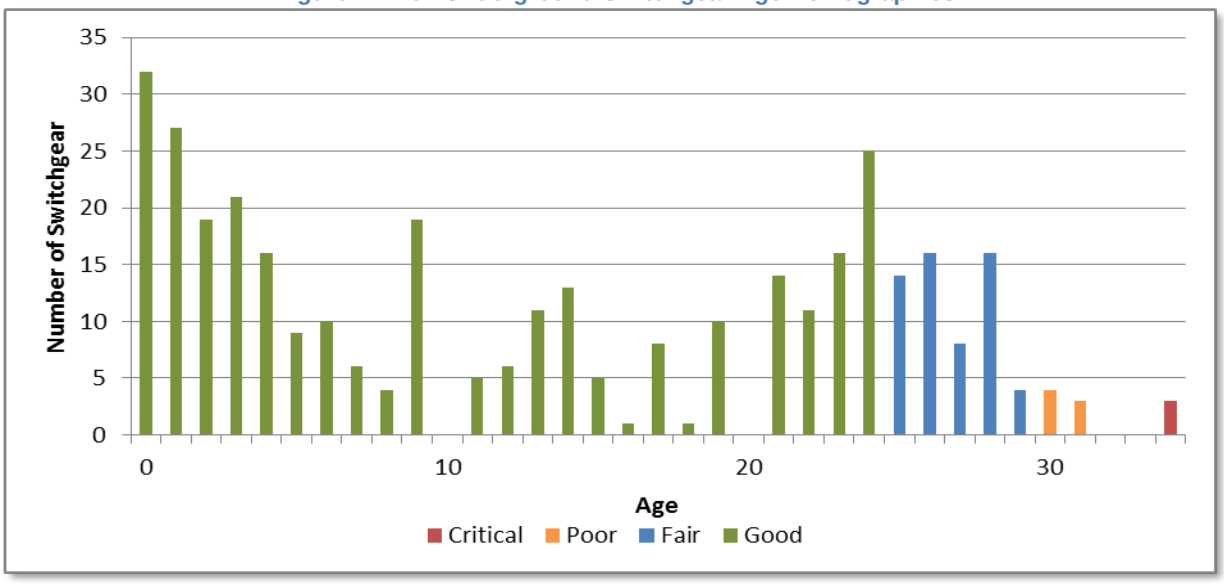
HOL's distribution switchgear asset class consists of 439 pad-mounted, 191 vault installed and 2 submersible types. There are many different configurations and types of switchgear in service due to the amalgamation of the former utilities and their varying policies for servicing customers. HOL is developing policies and procedures for incorporating these different practices in a consistent manner.

Figure 2.2.25 - Underground Switchgear Age Demographics



The condition assessment for underground switchgear is based on age alone. Critical and poor condition switchgears are considered to be over the ages of 35 (Weibull Analysis) and 30 (Historical Failures) respectively. These assets are considered to be at a higher risk of failure.

Figure 2.2.26 - Underground Switchgear Age Demographics



2.2.3.12 Underground Civil Structures

Hydro Ottawa's Underground Civil Structure asset class consists of underground duct banks, hand holes and various types of underground chambers forming a network through which cables may be installed. Distribution underground civil structures are used in areas where underground wiring is required for aesthetics or clearances, to improve reliability, to reduce the time to access and correct faulty wiring, to permit access in congested areas and to allow re-entry or expansion in areas where further excavation would be costly.

The asset class has been divided into two primary groups; Duct Structures and Underground Chambers. While duct structures are run to the unlikely event that they fail, underground chambers are maintained through a replacement and rehabilitation program based on regular condition assessment. Based on the currently available inspection data it is recommended that the program target a minimum of 10 underground chambers per year.

Table 2.2.7 - Civil Structure by Type

Civil Structure Type	Pre 1970	Post 1970	Unknown	Total
Cable Chambers	**760**	**2,017**	**731**	**3,508**
Precast	66	661	159	886
Cast in Place	694	1,284	551	2,529
Unknown/other	-	23	6	29
Pre-Cast Switch Cable Chambers	-	49	15	64
Handholes	**9**	**240**	**115**	**364**
Sidewalk Vaults	**-**	**34**	**-**	**34**
Equipment Pad	**-**	**3,300**	**18,040**	**21,340**
Miscellaneous Pad	-	32	2,164	2,196
Primary Pedestal	-	-	7	7
Secondary Pedestal Pad	-	1,642	2,671	4,313
Service Disconnect Pad	-	38	552	590
Switchgear Pad	-	23	238	261
Transformer Pad	-	1,565	12,408	13,973

2.2.3.13 Overhead Distribution Switches and Reclosers

Hydro Ottawa's distribution overhead switch and recloser asset class consists of all pole mounted load break switches, reclosers, fuse cut-outs and inline switches, with a primary voltage rating up to 44 kV. The primary purpose for this asset class is to provide a means to isolate or re-route a section of overhead line due to a fault condition or planned work.

The overhead switch and recloser program is typically a run-to-failure asset class unless a technical or health and safety issue have been identified.

Table 2.2.8 - Overhead Switch & Recloser Demographics

Switch Type	4.16 kV	8.32 kV	12.43 kV	13.2 kV	27.6 kV	44 kV	Total
Non-Load Break	1,610	2,293	39	1,342	1,467	483	7,234
Load Break	51	137	0	159	446	309	1,102
Cut-Outs	8,333	6,139	41	2,770	3,977	9	21,323
Reclosers	0	19	2	1	35	0	57

2.2.4 Capacity of the Existing System Assets

The following section outlines the degree to which the capacity of the existing system assets is utilized relative to planning criteria, referencing the related objectives as set out in section 1.3.1.4 System Operations Performance.

2.2.4.1 Stations Exceeding Planning Capacity

The planned capacity rating is defined as the sum of either the transformer's 10 day LTR or the allowable top loading rating if there is no published LTR for the remaining transformers following a single contingency loss of the largest element within the substation (N-1 contingency). An N-1 contingency for a station is defined as the loss of the largest transformer within the station. Note that for stations with a single supply and a single transformer, the planning rating is considered to be the rated capacity of the single unit (10 day LTR or allowable top load rating if there is no published LTR).

Station loading must be maintained within the planning capacity to allow for efficient transfer of load during an N-1 contingency reducing the duration of the interruption, while respecting equipment ratings.

Stations loaded above their planning capacity on the system peak day:

Table 2.2.9 - Stations Exceeding Planning Capacity

	Station	2013 System Peak Day Load (MVA)	Planning Capacity (MVA)	Planning Factor (%)
1	Bridlewood MS 28kV	48.9	25.0	196%
2	Rideau Heights DS	19.6	12.5	157%
3	Merivale DS	15.6	10.0	156%
4	Borden Farm DS	12.3	8.0	154%
5	Longfields DS	20.1	15.0	134%
6	Marchwood MS	43.7	33.0	132%
7	Startop MS	15.4	12.0	128%
8	Alexander DS	15.5	12.5	124%
9	Limebank MS	39.0	33.0	118%
10	Bayshore DS	11.6	10.0	116%
11	Centrepointe DS	15.9	14.0	114%
12	Stafford Road DS	15.5	14.0	111%
13	Fallowfield MTS	27.0	25.0	108%
14	Manordale DS	10.1	10.0	101%

2.2.4.2 Stations Approaching Rated Capacity

The rated capacity is defined as the sum of the top rating (LTR or allowable flat rating should an LTR not be published) of all transformers within the station. If the loading on a transformer exceeds this limit it will cause accelerated loss of life.

Transformer loading must be maintained within the rated capacity in order to avoid any accelerated loss of life to the unit.

Stations loaded within 90% of their rated capacity on the system peak day:

Table 2.2.10 - Stations Approaching Rated Capacity

	Station	2013 System Peak Day Load (MVA)	Rated Capacity (MVA)	Capacity Factor (%)
1	Richmond North DS	5.5	5.0	110%
2	Nepean TS	153.6	160.0	96%
3	Hawthorne TS	103.5	110.0	94%

2.2.4.3 Feeders Exceeding Planning Capacity

The planned capacity rating for a feeder takes three factors into consideration.

1. Coordination with lo-set instantaneous protection;
2. Feeder cold load pick up ability; and
3. Short term (8 hour) egress cable overload capabilities

Feeders must be maintained within the planning capacity to allow for efficient load transfer during an N-1 contingency situation, thereby reducing the duration of interruption while respecting equipment ratings.

Table 2.2.11 lists the feeders above 100% of their planning capacity.

1

Table 2.2.11 - Feeders Exceeding Planning Capacity

	Station	Feeder	2013 System Peak Day Load (A)	Rated Capacity (A)	Capacity Factor (%)
1	King Edward TK	404	229	85	269%
2	Rideau Heights DS	180F3	470	300	157%
3	Startop MS	6F10	391	300	130%
4	Bridlewood MS 28kV	BRDF3	399	310	129%
5	Russell TB	5304	326	255	128%
6	Russell TB	TB2JP (TB13)	313	255	123%
7	Parkwood Hills DS	190F5	356	300	119%
8	Stafford Road DS	200F6	341	300	114%
9	Limebank MS	7F2	344	310	111%
10	Jockvale DS	145F1	333	300	111%
11	Uplands MS	Q4801F8	342	310	110%
12	Kanata MTS	624F5	367	340	108%
13	Overbrook TO	TO1UT	273	255	107%
14	Kanata MTS	624F1	361	340	106%
15	Albion TA	2209	268	255	105%
16	Woodroffe TW	TW2UC	264	255	104%
17	Overbrook TO	1801	263	255	103%
18	Lisgar TL	TL7TS (TL19)	261	255	102%
19	Hinchey TH	TH2UL	257	255	101%
20	Carling TM	306	256	255	100%
21	Bilberry TS	77M2	310	310	100%
22	Carling TM	307	254	255	100%

2.2.4.4 Feeders Approaching Rated Capacity

The rated capacity is defined as the egress cable 8 hour loading limit. If the circuits are loaded above this limit for longer than 8 hours it will cause overheating and accelerated loss of life. Feeder loading must be maintained within the rated capacity in order to avoid damaging equipment and causing an accelerated loss of life to the cables.

Table 2.2.12 lists the feeders loaded within 90% of the rated capacity on the system peak day.

Table 2.2.12 - Feeders Approaching Rated Capacity

	Station	Feeder	2013 System Peak Day Load (A)	Rated Capacity (A)	Capacity Factor (%)
1	Rideau Heights DS	180F3	470	475	99%
2	Startop MS	6F10	391	420	93%

2.3 Asset Lifecycle Optimization Policies and Practices

This section documents HOL's asset lifecycle optimization policies and practices. The HOL approach is to maximize the lifecycle of an asset while providing a reliable service using a Plan, Deploy, Maintain, Evaluate, and Retire process (see Figure 2.3.1 - Asset Lifecycle Optimization). HOL optimizes the lifecycle of its assets by tracking and analyzing asset failure rates, historical asset Budget Program costs, and asset demographics. Effective testing, inspections and maintenance (TIM) programs ensure that adequate information is gathered about the assets to properly prioritize asset replacement and refurbishment while balancing operation and maintenance (O&M) costs.

Plan – determine the optimal equipment usage and arrangement based on requirements and develop standards and procedures for installation and maintenance;

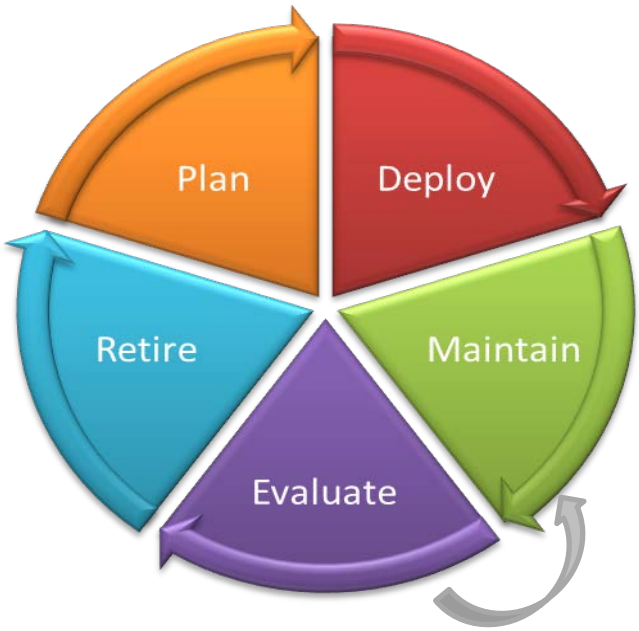
Deploy – install the equipment in the field following approved standards;

Maintain – inspect and maintain the equipment following internal standards, manufacturer recommendations and best practice;

Evaluate – review inspection and maintenance records to ensure the equipment continues to perform as required – based on evaluation, continue the Maintain cycle, or move on to Retire;

Retire – once the equipment no longer is able to meet requirements, it is disposed of in a sustainable manner, following environmental and regulatory requirements. Circle back to plan, where once again the equipment requirements will be evaluated before a replacement or re-arrangement is completed.

Figure 2.3.1 - Asset Lifecycle Optimization



HOL prioritizes asset replacement, refurbishment and maintenance by assessing the health condition of an asset. If insufficient data is available for an asset group, HOL will use age alone as the primary determinant of condition. HOL has implemented an Asset Investment Planning and Management software known as Copperleaf C55. One of the functions of this software is to act as a new asset repository, creating better defined health indices and reforming the TIM programs to gather required asset information for improving condition assessment processes.

2.3.1 Asset Replacement and Refurbishment

HOL plans asset replacement and refurbishment projects annually through the Asset Management Process (AMP) (see section 2.1 Asset Management Process Overview). The AMP mostly involves determining investment requirements under the System Renewal investment category of Chapter 5. The intention of the AMP is to document the asset management practices used by HOL as part of an optimized lifecycle strategy for distribution assets. The objectives of the Asset Condition Assessment are to demonstrate that the assets deliver the required functions at the desired level of performance and that this level of performance is sustainable for the foreseeable future while staying within the targeted levels of risk.

The HOL asset lifecycle optimization plan is achieved by forecasting equipment failures using available information regarding equipment demographics, inspection data and historical failure records.

2.3.1.1 Asset Replacement and Refurbishment Policies and Practices

HOL manages its asset replacement and refurbishment through proactive replacement, reactive replacement and refurbishment. HOL strategizes asset replacement and refurbishment through the use of asset failure curves, asset demographics and TIM programs. The asset replacement approach is determined based on the failure consequence of the asset, replacement costs, required lead-time for materials and the available information for that asset group.

HOL's two main drivers for asset refurbishment and replacement are age and condition. Assets with more established TIM programs continue to use health indexing based on condition to prioritize replacement. All other proactive replacement programs use age to prioritize replacement.

HOL is continuing to develop the TIM programs to achieve health indexing for all assets. Asset health indices will allow HOL to create a proactive replacement strategy for all assets, including reactively replaced assets.

2.3.1.1.1 Proactive Replacement

HOL has adopted a practice of proactive replacement for assets that incur higher failure consequences. This can be in the form of additional expenses or affect additional customers when replaced reactively following failure. Therefore, a more planned approach for acquiring and dedicating resources to minimize costs and customer impacts is required. HOL proactive replacement programs and rate of replacement are justified by reviewing historical asset failure rates and creating asset failure curves. Asset failure curves allow HOL to predict future failure rates to forecast replacement rates and costs. An increase in the failure rates may signify the need to increase replacement rates.

Proactive replacement of assets mitigates failure consequence by often minimizes costs, minimizes outage impact and decreases the project duration. HOL is striving to establish more asset information to maximize proactive replacement projects.

The evaluation of the technical life of assets focuses on the failure modes rather than the broader question of asset retirement, and as such does not consider assets retired from service for external reasons, such as capacity upgrades, relocations, and vehicle collisions. The ACA's focus on end of life failure provides appropriate models for forecasting proactive asset replacement requirements, but typically results in higher average age than would be appropriate for asset depreciation.

Asset replacement projects can also be driven by the need to upgrade the system to meet the needs of new developments and intensification or new system operation requirements. Additional replacement projects are developed through the management of assets to minimize health and safety concerns, reduce environmental impact and improve reliability.

HOL develops all details of replacement projects well in advance of construction to ensure all aspects of the projects are known and documented, maximizing efficiency by being fully aware of all risks and potential obstacles up front. The consequence of all projects are assessed for their potential risks and analysed to mitigate known risks. This is done in an attempt to maximize the benefits versus costs ratio. Business cases are prepared to justify the project and select the preferred alternative from various options by comparing costs, associated risks and benefits of each.

HOL has developed a consequence scoring and prioritization process to streamline selecting proactive projects. HOL assesses risk based on five objectives: Health and Safety, Environment, Reliability and Customer Impact, Asset Condition and Regulatory. Each of these categories is given a measure based on a seven step scale from "None" to "Severe". The scale measure describes the potential consequences of delaying the project. Refer to Section 2.1 for the full description of the process.

While it is preferred for all investments to be selected based on this prioritization, mandated investments will arise typically due to external drivers. When such investments occur they have reasoning clearly documented and are scored so that the impact to objectives is clearly understood and communicated. An example of this type of replacement would be due to equipment recalls, environmental regulation or major safety concerns.

2.3.1.1.2 Reactive Replacement

HOL has developed capital programs that manage assets through reactive replacement. These assets have minimal failure consequence, have spares readily available, and require minimal resources for installation. HOL reactive replacement strategy has been developed based on historical failure rates and considers utility best practices.

2.3.1.1.3 Refurbishment

Asset refurbishment is approached on a per asset case, or through an asset refurbishment program and utilizes results from inspections, manufacturer recommendations, internal standards and/or regulatory requirements as drivers. Asset refurbishment is thoroughly compared to asset replacement to ensure there is financial and/or operational benefit.

Refurbishment of an asset is a life extension investment to offset the planned replacement. HOL determines the best course of action, refurbishment or retirement, by examining:

- Asset remaining useful operating life;
- Life extension forecasted from refurbishment activity;
- Cost of refurbishment as compared to cost of replacement;
- Availability of replacement parts;
- Obsolescence of asset;
- Impact to reliability, refurbishment outage vs. replacement outage;
- Refurbishment warranty; and
- Asset remaining financial life: cost of de-recognition if replaced;

2.3.1.2 Maintenance Planning Criteria

Annual review of the HOL maintenance programs are completed through the Testing, Inspection and Maintenance Planning Process (TIM) and documented in the Annual Planning Report (Attachment B-1(B)) TIM section. The TIM Planning Report was developed to serve as a summary and guide of the current activities, data collection methodologies as well as to identify the gaps in the existing practices. HOL's TIM programs are crucial to ensuring a reliable and sustainable distribution system by ensuring that all assets are effectively meeting requirements. Information from the TIM programs feed back into the ACA to allow for effective life-cycle

planning of assets. Currently, there are many different types of testing, inspection and maintenance activities that are used to gain asset information, health information required for the determination of replacement and/or maintenance prioritization in order to increase asset reliability, safety and longevity.

The purpose of the HOL TIM programs is to test, inspect and maintain the equipment and to gather equipment information for use in asset lifecycle planning. HOL retains maintenance records for assets used to optimize asset replacement, refurbishment, and maintenance activities. HOL currently splits the maintenance activities into two groups; distribution maintenance and station maintenance.

Through the TIM Plan the annual O&M spend is tracked by maintenance program to ensure an optimal balance between inspection and maintenance versus replacement is achieved.

2.3.1.2.1 Criteria and Assumptions

HOL maintenance planning criteria and assumptions are asset dependent and rely on either internal standards or regulatory requirements (OEB Distribution System Code Appendix C – Minimum Inspection Requirements). Internal maintenance program requirements follow industry best practises or are formed through HOL historical experience. HOL develops maintenance and replacement programs by comparing their associated benefits and costs: it may be practical to replace an asset if the cost of maintaining the asset outweighs the value of its replacement.

2.3.1.3 Preventive Inspection and Maintenance Programs

HOL TIM program activities include visual or infrared inspection as well as more intrusive testing of equipment condition and operation. The TIM program also includes maintenance activities referring to physical work on equipment. Most of HOL asset maintenance activities are on a cyclic schedule. The cycle period is selected based on manufacturer's recommendation, regulatory requirement or internal experience and standards.

Table 2.3.1 outlines the inspection and maintenance cycles of each program. The following sections describe the HOL inspection and mainteneance programs, further details can be found in the Testing, Inspection and Maintenance Plan, included in the APR.

1

Table 2.3.1 - Maintenance Programs

	TIM Type	Cycle	Type
Substation	Station IR Scans	Annually	Predictive
	Switchgear Inspections	Annually	Preventative
	Breaker & Recloser	Every 4-6 Years	Preventative
	Station Switches	Annually	Preventative
	SCADA Inspections	Annually	Preventative /Predictive
	Relay	Every 4-6 Years	Preventative
	Station Inspections	Monthly	Predictive/Corrective
	Battery Maintenance	Annually	Predictive
	Transformer Maintenance	Every 3-5 Years	Preventative
	Transformer Doble	Every 3-5 Years	Predictive
	Transformer Oil Analysis	Annually	Predictive
	Transformer Tapchanger Maintenance	Every 3-5 Years	Preventative /Predictive
Distribution	Padmounted Switchgear IR and Visual	Every 3 Years	Predictive/Corrective
	Padmounted XFMR IR and Visual	Every 3 Years	Predictive/Corrective
	O/H IR Inspection	Every 3 Years	Predictive
	Vault Maintenance	Not Defined	All
	Vegetation Management	Every 2 or 3 Years	Preventative /Corrective
	Pole Inspection	Every 10 years	Predictive/Corrective
	Critical Switch Inspection	Every 3 Years	Preventative
	Insulator Washing	Annually	Preventative
	Switchgear CO_2 Washing	Every 3 Years	Preventative
	Cable Inspection	120 segments annually	Predictive
	Manhole Inspections	10 Year	Corrective
	Graffiti Abatement	Routinely	Corrective

2.3.1.3.1 Station Infrared (IR) Inspections

Infrared (IR) inspection on station equipment is completed in conjunction with more specific equipment inspection. The IR inspection checks equipment for hot spots to indicated loose connections, defective equipment, overloading, contamination, short circuits and ground faults. HOL performs IR scanning, internally, on station equipment.

2.3.1.3.2 Station Switchgear Maintenance

Switchgear General Maintenance

Switchgear undergoes inspections, as part of the monthly cycle, that check the switches, over current relays, position indicator, heaters, breaker tools, and breaker and racking mechanism operation.

Breaker Maintenance

The current TIM activities for circuit breakers include: visual inspection and electrical, mechanical, and operational tests. Visual inspection ensures that the breakers are clean, there are no signs of arcing or leaking oil, and there is no damage to the breaker or arc chute. Electrical testing includes performing insulation resistance and contact resistance testing. Mechanical tests include: cleaning the bushing, checking for any leaks around the gaskets, cleaning, lubricating and testing the operating mechanism, checking the contacts, and tightening all bolts, pins, and connections. Operational testing of the breaker checks the operating mechanisms, and ensures the proper operation of the breaker and the charging motor.

Station Recloser Maintenance

Recloser maintenance includes: visual inspection, electrical testing, mechanical testing and dielectric sampling. The visual inspection checks the bushings, contacts and liquid level and includes an IR scan of the recloser and its components. The electrical, mechanical, and operational inspection includes checking mechanical connections, testing insulation resistance and recloser function test to ensure proper operation.

Station Switch Maintenance

Switches undergo visual inspection on a monthly basis. Visual inspection checks for issues with the arc shoots, arc tips, broken insulators, burned insulators, and dirty components. The visual

inspection is completed to ensure that the switch has no issues that could indicate a problem with day to day operation.

High Voltage Fuse Maintenance

High voltage fuse inspection involves: IR scans, visual inspection and cleaning and clip pressure inspection. The visual inspection includes: inspecting the fuse holders, insulators and fuse for breaks, cracks, burns, pitting, and indication of flashover and signs of deterioration. The IR inspection checks the fuse holder to ensure the components are under the threshold temperature.

2.3.1.3.3 Supervisory Control and Data Acquisition (SCADA) Maintenance

Supervisory Control and Data Acquisition (SCADA) is a control system that allows for the monitoring and control of compatible electrical equipment in the HOL electrical system. The maintenance performed on SCADA controlled equipment includes visual inspection, checking communication, cleaning, torquing, function testing and ground inspection.

2.3.1.3.4 Relay Maintenance

Relays are currently undergoing complete inspections every 4 to 6 years. Visual inspections are part of the monthly stations inspection and check for obvious equipment deficiencies. Electrical, mechanical and operational inspections identify loose connections, broken studs, burned insulation, dirty contacts, setting configuration and proper operation. IR scans are completed as part of the station annual IR scan and detects equipment operating over the manufacturers temperature specifications.

2.3.1.3.5 Station Visual Inspection

The Station Visual Inspection program is used to assess the condition of the station yard, the station building exterior and interior, the station security, and general equipment condition. The inspections are conducted monthly.

2.3.1.3.6 Battery Maintenance

The station battery and battery charger are inspected by completing voltage measurements and visual inspection of the direct current (DC) supply components. Included in the voltage measurements are recording individual cell voltages, the battery charger normal charging

voltage and the battery charger equalization voltage. The voltage of the individual cells will ensure that they are holding their nominal level and will confirm the cell is in good condition. The charging voltages are taken to ensure the battery charger is set up to charge the battery at the manufacturer's recommendations. Visual inspections are completed for the bonding connections, the battery and battery charger as well as all connecting equipment. The visual inspection determines if there are low electrolyte levels and if corrosion exists at the battery terminals.

2.3.1.3.7 Station Transformer Maintenance

Transformer maintenance currently includes: visual inspection, electrical tests, mechanical tests and oil sampling. The visual inspection involves current and voltage readings, temperature readings, liquid level check, physical condition assessment and pressure/vacuum gauge readings.

The visual inspections of current, voltage and temperature readings ensure that the transformers are operating within the acceptable limits. If the levels are measured outside of the specifications, investigation will be required to determine the root cause and remediation plans.

Liquid, pressure and vacuum level readings are checked to ensure that the transformer is not leaking in any way. If the readings are out of the acceptable range, the stations office is contacted to provide immediate support or schedule follow-up action.

2.3.1.3.8 Station Transformer Doble Testing

Doble testing equipment is being used to assess the overall power factor, turns ratio testing, leakage reactance and exciting current of the transformer. These tests are used to detect moisture in the oil or insulation, detect contamination in the transformer bushing, determine the electrical insulation quality, and locate bad connections and winding movement. The Doble equipment provides test results and expected values and thresholds to effectively translate the results. Doble testing, DGA testing and oil quality analysis complement each other to provide clear indication of the overall health of the transformer.

2.3.1.3.9 Station Transformer Oil Analysis Testing

Transformers undergo dissolved gas analysis (DGA) and oil quality analysis annually. The DGA and oil quality analyses are an important diagnostic tool used to monitor the condition of the unit. Emphasis is placed on these tests for detecting insulation breakdown, water in the oil, stressing of the coils, localized overheating and arcing that can lead to failure of the transformer. Currently, HOL sends oil samples to an oil testing laboratory, uses DGA portable equipment and uses DGA online monitoring equipment. The oil testing laboratory uses sophisticated lab equipment that creates a full analysis of the oil sample, compares the results to any previous transformer oil samples, and specifies detailed recommendations for the transformer. If the laboratory processing lead time is too lengthy, HOL will use portable DGA equipment for immediate results. The online DGA equipment is used for continuous monitoring of transformer gas concentrations and can be used to set alarms at specific gas concentration thresholds. DGA online monitoring systems are being installed as part of HOL standards and are capable of sending DGA data to the PI server data historian.

DGA and oil quality tests identify abnormalities within the transformer and provide detailed information to allow for sound decision making for future operation and maintenance of the transformer.

2.3.1.3.10 Tap Changer Maintenance

Oil Filled (Filtered) Tap Changers

Oil filled tap changer TIM activities include recording position of the tap changer, inspecting the physical and mechanical condition, verifying correct auxiliary device operation, verifying correct liquid level in all tanks, performing tests as recommended by the manufacturer, verifying operation of heaters and verifying grounding. An internal inspection is also conducted and includes removing of the oil and cleaning carbon residue and debris from compartment, inspecting the contacts for wear and alignment, tightening all electrical and mechanical connections to calibrated specifications, inspecting the tap changer components for signs of moisture, cracks, electrical tracking or excessive wear and then refilling the tank with filtered oil.

Oil/Vacuum Filled Tap Changers

Oil/vacuum tap changer inspection includes: recording position of the tap changer, inspecting the physical and mechanical condition, verifying correct auxiliary device operation, verifying vacuum level, performing tests as recommended by the manufacturer, verifying operation of heaters, verifying grounding, and inspecting the vacuum bottles for wear or erosion.

2.3.1.3.11 Infrared (IR) and Visual Inspection

HOL performs infrared (IR) and visual inspection for many of its assets. The IR inspections allow crews and contractors to examine equipment operating temperature to detect defective components, poor connections, or overloaded equipment which can indicate the potential for failures. Visual inspections are important to monitor cleanliness, ease of access, obtain updated nomenclature and equipment information, and to assess damage and any potential follow-up activities required.

In order to effectively use the IR scanning information, an equipment health index was created and is used for various pieces of equipment. The condition rating is based on the temperature difference between the reference temperature and the equipment's actual measured temperature. Equipment that is within the critical temperature range has an Outage Management System (OMS) ticket created to schedule immediate repair. It is the responsibility of the area supervisor to schedule the work and close out the ticket when the issue is verified to be resolved.

Padmounted Switchgear

The padmounted switchgear inspection consists of IR scanning and a visual inspection of air-break switchgear. The IR scan detects loose connections, tracking, overloaded equipment, and other heat related problems. Visual inspection includes recording equipment information as well as checking for swollen elbows, exposed electrical hazards, operating hazards, rusting and graffiti.

Padmounted and Kiosk Transformers

The padmounted and kiosk transformer inspections consist of an infrared scan and a visual inspection. Infrared scanning detects loose connections, tracking, equipment overload, and other heat related problems. Visual inspection checks for swollen elbows, exposed electrical

hazards, operating hazards and graffiti. Additional patrol inspection is performed as a result of the Graffiti Abatement and Repainting program.

Overhead Equipment

Overhead switches, transformers, lines, and associated attachments are inspected through the IR Scanning Program. The IR Scanning Program consists of performing infrared inspections on overhead equipment from ground level. Equipment that is over a temperature threshold is flagged as requiring further investigation.

2.3.1.3.12 Vault Maintenance

HOL has approximately 1500 vaults in its system, most of which are customer owned. HOL is in the process of creating a vault maintenance program. Customer owned vaults are the customers' responsibility to maintain along with the containing equipment. If no current maintenance is being performed on customer owned vaults, HOL will recommend that maintenance is performed by the customer. In the rare case that a customer does not complete maintenance on their vaults, and there are obvious issues, the vault could be reported to the Electrical Safety Authority (ESA) for follow-up.

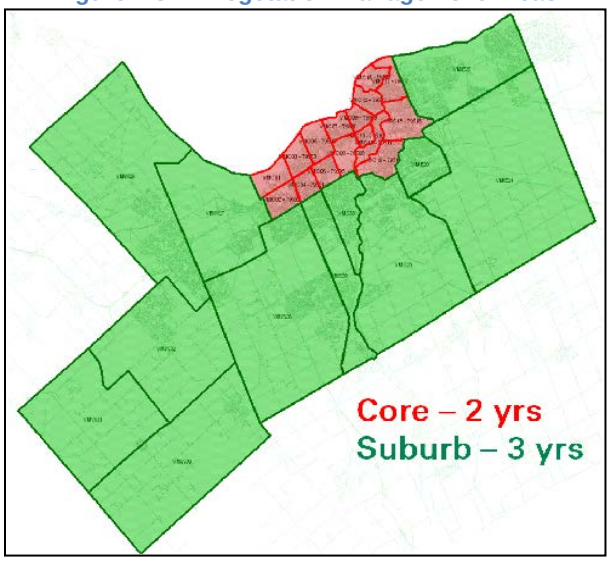
Vault maintenance being performed is at the discretion of the customer or the contractor completing the work. Most often vault maintenance includes visual inspection of the civil structure, ventilation fans, and all electrical equipment, cleaning of the switchgear, transformer(s), breakers, the vault floors and any other required equipment, IR scanning of the electrical equipment, torquing connections, inspecting grounding and lighting and any other supplementary maintenance.

2.3.1.3.13 Vegetation Management

Vegetation that encroaches on the distribution lines on any right-of-way is managed to ensure system reliability and public safety. The HOL's service territory is currently divided into regions for vegetation management: 12 suburb and 16 core areas (Figure 2.3.2). Third party arborist contactors are hired to maintain certain vegetation areas annually. Recently, HOL undertook a project to evaluate each of the circuits in the distribution system through physical inspection. This produced a large amount of data regarding tree species to aid in a potential redevelopment of the vegetation management program to improve upon the effectiveness of the program. Also

identified during the inspections were a number of circuits with overhanging branches. As a result, HOL is working through a storm hardening activity to remove the overhanging branches in an effort to further improve reliability.

Figure 2.3.2 - Vegetation Management Areas



2.3.1.3.14 Pole Inspections and Testing

One of HOL's largest asset classes is distribution poles and attached hardware. These assets are used to support overhead distribution and sub-transmission conductors throughout the City. Maintaining these assets is essential for a reliable and safe system.

HOL currently performs visual inspection and drill testing on poles. Visual inspections record detailed information about the pole, the attached hardware and any other relevant information. This information is used in conjunction with the drill test to prioritize pole replacement, hardware replacement or to create new designs that will integrate with the present configuration. Drill assessment is a non-destructive testing method using an International Distribution Network (IML) Resistograph drill which measures the density or resistivity of the wood against the drill bit. The drill test provides an overall indication of rot, void, and solid wood thickness that can be used to calculate the remaining strength of the pole.

2.3.1.3.15 Critical Switches Inspection

HOL currently has a critical switch program with the purpose of maintaining and inspecting switches that are deemed a high priority. These switches are selected based on the requirements to interrupt higher loads, supply many customers, or critical customers such as hospitals. The cyclic inspection program will ensure all areas will be visited, and problems detected before they lead to system failures that may:

- Impair the safety of HOL employees or the public at large;
- Impair system reliability and reduce the quality of service to our customer;
- Seriously reduce the life expectancy of the equipment and increase costs; and/or
- Adversely affect the environment.

Currently, the critical switch maintenance includes a visual and mechanical inspection, electrical tests, and comparison of resistance tests with similar connections. The mechanical and visual inspection includes a visual check of the physical appearance of the mechanical and electrical connections, cleaning of the switch, and mechanical operator test. The electrical test includes connection resistance checks, equipment torquing, and Megger checks on each pole and/or control wiring.

2.3.1.3.16 Washing

Insulator Washing

HOL has adopted an extensive insulator washing program with full washing of critical 44 kV, 27.6 kV and 13.2 kV circuits.

Washing is used to clean insulators with contamination build-up. Contamination decreases the insulation strength and causes tracking and flashover. This arcing causes electrical losses but can also lead to pole fires, further equipment damage, and outages to the system. Currently, only porcelain insulators are being washed as part of the program.

The program was revisited in 2013 and the insulator routes were modified based on several criteria. The main selection criteria were system voltage, type of traffic or nearby industry, numbers of recorded pole fires and percentage of porcelain insulators.

The insulator wash is a supplementary activity from those stated in the OEB's Minimum Inspection Requirement document

Padmounted Switchgear CO_2 Wash

All identified air-brake switchgear are Carbon Dioxide (CO_2) washed by contractors to remove contamination, such as road salt or dirt, that contributes to tracking and flashover. To eliminate the contamination's impact on the IR results, the switches are washed prior to performing IR scan. The carbon dioxide is mixed with clean compressed air at the spraying nozzle and safely removes surface contamination from both energized and de-energized internal equipment. CO_2 wash allows switchgear to be cleaned while energized, is environmentally friendly, safe, and will increase system reliability by removing surface contamination that can lead to flashover.

Cable Inspection

Underground cables are patrol inspected during manhole inspections. Select condition testing of XLPE cable is done annually in the winter through a cable testing program with National Research Council of Canada (NRC). Specific cable segments are tested using a polarization / depolarization technique and the results are compared to reference cables. Test locations are determined based on fault history, age and future planned replacement projects. Test results provide input to HOL's cable replacement and cable injection strategy.

2.3.1.3.17 Civil Structure Inspections

The manhole inspection program targets 300 manholes annually as part of a 10 year inspection cycle. Underground chambers are also inspected through regular work activities when crews perform scheduled work in manholes and handholes.

2.3.1.3.18 Graffiti Abatement

The objective of the Graffiti Abatement program is for painting rusted equipment, graffiti removal, refurbishment and removal of eyesores and extending equipment life when necessary. Currently, equipment requiring attention is identified through regular patrol by a contractor. The Graffiti Abatement program was developed in response to the City of Ottawa Graffiti By-Law to ensure HOL keeps its property free of graffiti. It also allows HOL to work cooperatively with the City of Ottawa By-Law department to address criminal acts of graffiti to deter future acts of vandalism.

2.3.2 Asset Life Cycle Risk Management

HOL uses several different TIM programs and activities to provide different approaches to asset failure mitigation; predictive, preventive and corrective maintenance. The HOL maintenance programs may use more than one approach to minimize asset failure and for input into strategic asset management planning.

2.3.2.1 Methods

2.3.2.1.1 Predictive Maintenance

HOL practices predictive maintenance techniques to mitigate asset failure by evaluating testing and inspection information to identify when proactive or corrective maintenance is required to ensure that the equipment continues to meet requirements.

Infrared Scanning

HOL proactively performs infrared (IR) scanning on most equipment as a predictive tool for maintenance. Equipment that undergoes IR scans includes but is not limited to:

- station transformers;
- station switchgear;
- station switches;
- station terminations;
- station batteries;
- overhead conductors and terminations;
- padmounted transformers;
- padmounted switchgear;
- polemounted transformers; and
- supervisory control and data acquisition (SCADA) system equipment

Table 2.3.2 - Infrared Condition Rating

Critical - (>75°C), immediate repair
Major Problem - (>36°C-75°C), repair as soon as possible
Intermediate - (>10°C- 36°C)
Minor - 10°C or less

IR scans are a useful tool to locate overloaded equipment, bad termination, or failed equipment to prioritize maintenance activities to eliminate the potential risk of failure. HOL uses a conditioned rating to prioritize follow-up preventative maintenance (see Table 2.3.2).

Dissolved Gas Analysis

Substation transformers and tap changers undergo dissolved gas analysis (DGA) and oil quality analysis annually. The DGA and oil quality analyses are an important diagnostic tool used to monitor the condition of the equipment. DGA and oil quality tests identify abnormalities within the transformer and tap changer and provide detailed information to allow for sound decision making for future operation and maintenance practices to ensure the equipment continues to run efficiently.

Station Batteries and Chargers

HOL performs testing on substation direct current (DC) systems to assess the condition of the charger and the battery. Testing ensures the charging system is performing as expected and evaluates the individual cell health. The cell health condition predicts any problematic cells in the battery to flag corrective maintenance or replacement before a failure can occur.

Poles

HOL poles are visually and drill tested for condition assessment and as input to develop the health indexing. The visually inspection and drill testing are a predictive approach used to calculate the remaining strength of the pole and any attachments. The remaining strength is used to assess if the pole is adequate, if it needs immediate replacement, or to forecast when replacement will be required. The visual inspection identifies any risks of failure to pole attachments which includes insulators, crossarms, guying or anchoring. Any immediate concerns are dealt with and follow up work is scheduled for resolution.

2.3.2.1.2 Preventive Maintenance

HOL performs preventive maintenance on distribution and station assets. Preventive maintenance is an approach where cyclic testing, inspection, and maintenance results in safe and reliable equipment operation by proactively identifying issues that could lead to future concerns.

Insulator Washing

HOL executes overhead insulator washing to decrease flashovers and potential pole fire due to contamination, such as salt spray, dust or pollution, which can cause tracking. Insulator washing is done in selective areas deemed to be critical based on the following factors: system voltage,

type of traffic or nearby industry, numbers of recorded pole fires and percentage of porcelain insulators.

CO_2 Washing

Air-brake switchgear are carbon dioxide (CO_2) washed to remove contamination in order to reduce the probability of tracking and flashover. The carbon dioxide is mixed with clean compressed air at the spraying nozzle and safely removes surface contamination from both energized and de-energized internal equipment. CO_2 washing allows switchgear to be cleaned while energized, is environmentally friendly, safe, and will increase system reliability by removing surface contamination that can lead to flashover.

Vegetation Management

The HOL vegetation management program combines preventive and corrective activities. The preventative work is regular trimming that occurs on a 2 or 3 year cycle depending on region aimed at maintaining proper clearances to lines. This trimming manages the majority of trees in HOL right of ways. The vegetation management program removes tree hazards that are within the encroachment limits to decrease tree related failures and interruptions. Corrective work includes unpredictable vegetation activities and includes customer calls for tree hazards, emerald ash trees affected by the emerald ash borer, and emergent work from storms.

Critical Switch Program

The purpose of HOL's critical switch program is to maintain and inspect switches that are deemed to have a high consequence of failure. These switches are selected based on the requirements to interrupt higher loads, supply many customers, or critical customers such as hospitals. The cyclic inspection program ensures all areas are visited, and problems detected before they lead to system failures that may:

- Impair the safety of HOL employees or the public at large;
- Impair system reliability and reduce the quality of service to our customers;
- Seriously reduce the life expectancy of the equipment and increase costs; and/or
- Adversely affect the environment.

Station Equipment

Substation equipment has a larger failure consequence as compared to distribution equipment based on an increase in number of customer affected by any failure, increased equipment procurement time and higher cost, and as such, has more regular, rigorous and frequent testing, inspection and maintenance activities. The following list details the regular maintenance performed on station equipment.

- The oil from transformers and tap changers is drained to perform an internal visual inspection and the oil is replaced to eliminate any potential contamination;
- Tap changers are cleaned and tested to ensure reliable operation;
- Switchgear is cleaned thoroughly;
- Breakers are tested and calibrated to ensure adequate timing
- Breaker racking mechanisms are cleaned, greased and tested.

During these routine maintenance activities any problematic components identified are proactively replaced.

2.3.2.1.3 Corrective Maintenance

Corrective maintenance activities are identified through visual inspection or by equipment failure indication. HOL uses predictive and preventive maintenance to minimize corrective maintenance which can typically result in longer interruption duration and higher overall costs. Reactive maintenance is commonly performed on equipment with low consequence of failure or due to unpredicted failure.

Corrective maintenance is prioritized in HOL's tracking system (Outage Management System, OMS) depending on the criticality of the work. Issues identified as a reliability, safety or environmental concern are resolved immediately and progress on other issues is tracking through the OMS to ensure completion in a timely manner.

2.3.2.2 Information Collection and Analyses

HOL is currently in the process of maximizing digital collections of maintenance information. Digital collection of information, through the use of ruggedized tablets, optimizes the ability to perform data analyses and allows for more effective implementation of health indexing and

project prioritization. HOL is reviewing its asset health index to identify the gaps in the inspections process. Identifying the gaps will allow the maintenance programs to improve and evolve to provide more qualitative results.

The TIM Plan documents HOL's current programs; including the programs schedule, performance indicators, data governance, corrective maintenance activities and program gaps (refer to the Annual Planning Report Testing Information and Maintenance – Data Governance for the information collected by HOL, Attachment B-1(B)).

2.3.2.3 Asset Risk Analysis

HOL risk analysis is completed as part of the Asset Management Process. The risk is calculated using objective weighting and risk scoring (see Section 2.1.2 Asset Management Process Components) that prioritizes activities that address a higher level of risk.

2.3.2.4 Risk Analyses and Prioritizing Capital Expenditures

HOL risk analysis and capital project prioritization is completed as part of the Asset Management Process. The capital expenditures are prioritized to maximize benefit to cost (see Section 2.1.2 Asset Management Process Components).

3 Capital Expenditure Plan

The capital expenditure plan details the system investment decisions which are made through the asset management and capital expenditure planning process. Investments are detailed by investment category, HOL Capital Program and Budget Program for the historic years of 2011 through 2015 and the forecast years of 2016 through 2020.

3.1 Summary

HOL's Capital Expenditures are broken into categories based on the following hierarchy: Investment Category, Capital Program followed by Budget Program, as shown in Table 3.1.1 along with the primary driver. For a description of each driver refer to Table 2.1.1 - Driver Descriptions.

Table 3.1.1 - Capital Expenditure Categories

Investment Category	Capital Program	Budget Program	Primary Driver
System Access	Plant Relocation	Plant Relocation & Upgrade	3rd party requirements
	Residential	Residential Subdivision	Customer service request
	Commercial	New Commercial Development	Customer service request
	System Expansion	System Expansion	Customer service request
	Stations Embedded Generation	Embedded Generation Projects	Customer service request
	Infill & Upgrade	Infill Service (Res & Small Com)	Customer service request
	Damage to Plant	Damage to Plant	Mandated service obligation
	Metering	Suite Meters	Mandated service obligation
System Renewal	Station Assets	Stations Transformer Replacement	Assets at end of service life – failure risk
		Stations Switchgear Replacement	Assets at end of service life – failure risk
		Stations Plant Failure	Assets at end of service life – failure
	Stations	Stations Enhancements	Assets at end of service

	Refurbishment		life – substandard performance
	Distribution Assets	Planned Pole Replacement	Assets at end of service life – failure risk
		Insulator Replacement Program	Assets at end of service life – high performance risk
		Elbow & Insert Replacement	Assets at end of service life – substandard performance
		Distribution Transformer Replacement	Assets at end of service life – failure risk
		Vault Rehab or Removal	Assets at end of service life – failure risk
		Civil Rehabilitation	Assets at end of service life – failure risk
		Cable Replacement	Assets at end of service life – failure risk
		Switchgear New & Rehab	Assets at end of service life – failure risk
		O/H Equipment New & Rehab	Assets at end of service life – failure risk
		Plant Failure	Assets at end of service life – failure
	Metering	Remote Disconnected Smart Meter	Assets at end of service life – substandard performance
System Service	Stations Capacity	Stations New Capacity	Capacity constraint
	Distribution Enhancement	Line Extensions	Capacity constraint
		System Reliability	Reliability
		Distribution Enhancements	System efficiency
		System Voltage Conversion	Capacity constraint
	Automation	Distribution Automation	Reliability
		Substation Automation	System efficiency
		SCADA Upgrades	System efficiency
		RTU Additions	System efficiency
General Plant	Hydro One Payments	Hydro One Payments	System capital investment support

	Facilities Management	Facilities Management	Non-system physical plant
	Fleet Replacement	Fleet Replacement	System capital investment support
	Tools Replacement	Tools Replacement	System maintenance support
	IT Life Cycle & On-going Enhancements	IT Life Cycle & On-going Enhancements	Business operations efficiency
	IT New Initiatives	IT New Initiatives	Business operations efficiency
	ERP System	ERP System	Business operations efficiency
	Customer Service	Customer Service	Business operations efficiency
	Operation Initiatives	Operation Initiatives	Business operations efficiency
	Facilities Implementation Plan	Facilities Implementation Plan	Non-system physical Plant

The following sections outline the descriptions of the Capital Programs and Budget Programs by Investment Category.

3.1.1 System Access

System Access investments, as defined in the Chapter 5, Section 5.1.1 Investment Categories are "modifications (including asset relocation) to a distributor's system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system". Figure 3.1.1 shows the System Access financial hierarchy and drivers.

Figure 3.1.1 - System Access Financial Hierarchy and Drivers

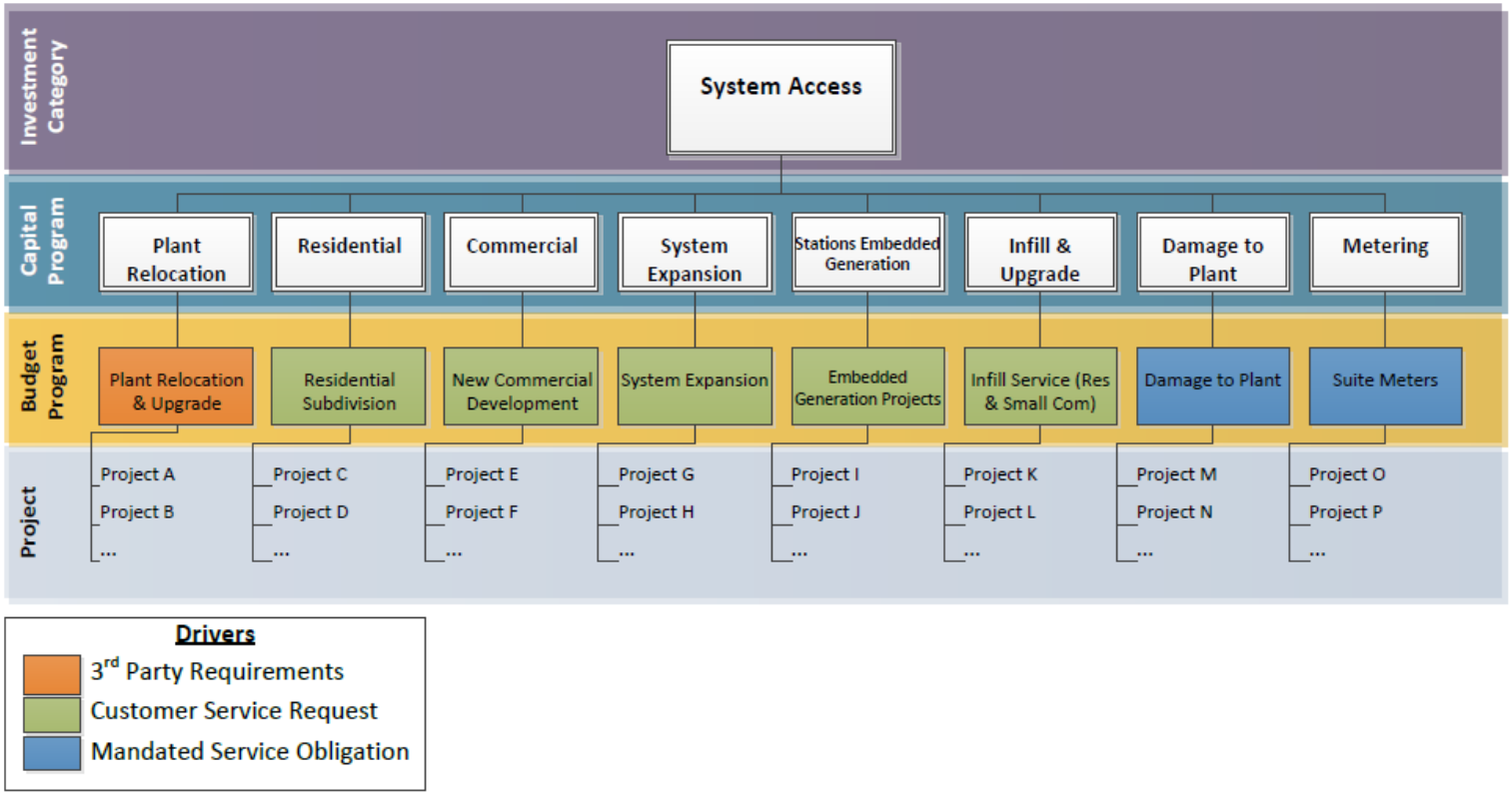


Table 3.1.2 - System Access Capital Program & Budget Program Descriptions

Capital Program		Budget Program	
Name	**Description**	**Name**	**Description**
Plant Relocation	• Work triggered by road widening, relocation and upgrade of plant during relocation and any plant removal due to conflict; • Typically 50% contributed capital	Plant Relocation & Upgrade	• Relocation or upgrade of HOL owned or joint-use overhead lines or underground; • equipment to permit for safe limits of approach.
Residential	• Connection of new subdivision developments; • Exclusive of work considered under Infill & Upgrade	Residential Subdivision	• To connect new residential subdivisions consisting of townhomes, semi-detached, single, or any combination of housing units; • Includes alternative bid and HOL built subdivisions; • Trunk, primary & secondary distribution infrastructure all considered within scope
Commercial	• To connect new developments with secondary voltage at or above 600V; • Exclusive of work considered under Infill & Upgrade	New Commercial Development	• New developments serviced via padmounted equipment (switchgear and/or transformers) or via a vault
System Expansion	• An addition to the distribution system in response to a request for	System Expansion	• A demand driven addition to a distribution feeder in response to a request for

	additional customer connections that otherwise could not be made		additional customer connections; for example a line extension
Stations Embedded Generation	• Projects that HOL undertakes to ensure the system can accept customer embedded generation connections while ensuring reliability of the existing system is maintained	Embedded Generation Projects	• Connection of customer driven embedded generation projects; • Includes metering, service connection and protection and control as required
Infill & Upgrade	• Residential infill and small commercial connections (one-offs); • Excluding those covered under Residential or Commercial; • Appendix G in HOL's Conditions of Service outlines fees, servicing standards, and conditions for infill and upgrade connections to the distribution network	Infill Service (Res & Small Com)	• Infill service or service upgrade for either residential or small commercial developments, i.e. services that do not require padmounted equipment or vault installations
Damage to Plant	• Replacement of harmed assets that has resulted in the loss of functional use or a safety hazard and are caused by a third party	Damage to Plant	• Unplanned replacement of harmed assets as caused by a third party

	(e.g. motor vehicle collision, cable dig-in, etc.); • Asset may be no longer functional or has an aesthetic condition beyond normal wear and tear; • Target 100% recovery of cost from the third party; however, where tracking information is not available, HOL absorbs the cost or may attempt at recovery from its insurer; • Includes damaged distribution or stations assets, excluding metering		
Metering	• Retrofit or installation of suite meters in commercial installations capable of measuring consumption on a per dwelling (as opposed to bulk) basis	Suite Meters	• Retrofit or installation of suite meters (retrofit of bulk meters) for commercial buildings; • Focus of the program is on residential retrofits and new construction in vertically arranged establishments with a minimum of 25 units

3.1.2 System Renewal

System Renewal investments, as defined in Chapter 5, Section 5.1.1 Investment Categories "involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services". Figure 3.1.2 shows the System Renewal financial hierarchy and drivers.

Figure 3.1.2 - System Renewal Financial Hierarchy and Drivers

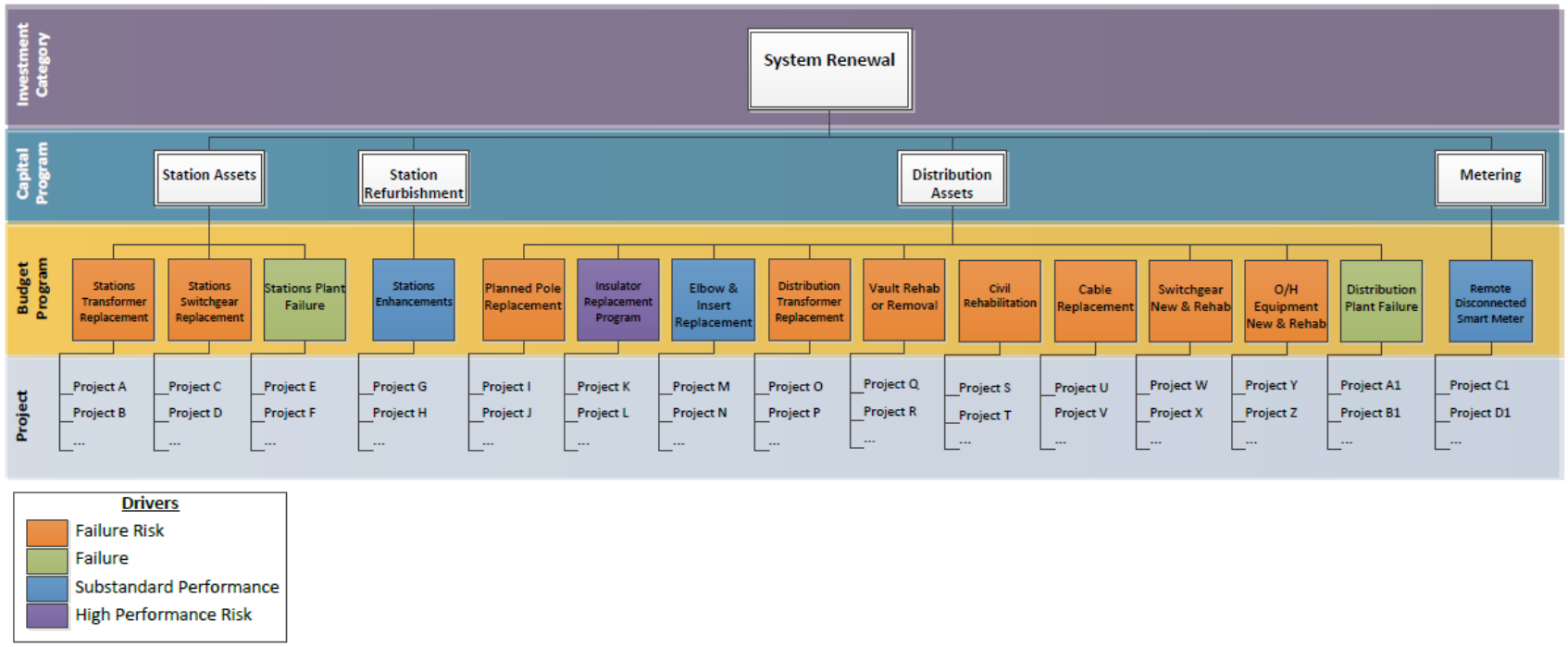


Table 3.1.3 - System Renewal Capital Program & Budget Program Descriptions

Capital Program		Budget Program	
Name	**Description**	**Name**	**Description**
Station Assets	• Sustainment of discreet stations assets based on condition (Health Index) and prioritization (See Section 2.1 Asset Management Process Overview)	Stations Transformer Replacement	• Station transformer refurbishment (life extension), or replacement as guided by the Asset Management Planning process
		Stations Switchgear Replacement	• Stations switchgear and relay refurbishment (life extension), or replacement as guided by the Asset Management Planning process
		Stations Plant Failure	• Unplanned replacement of failed station assets; • In cases where there is no full functional failure (causing an interruption), or immediate safety or environmental concern then work should be planned and prioritized based on crew and resource availability (where work is not considered to be an emergency); • If the equipment has been damaged by a third party then it is considered under Damage to Plant
Stations	• Repairs and/or	Stations	• Repairs, refurbishment and/or

Refurbishment	refurbishment of existing station building or property assets for the purposes life extension or safety/regulatory requirements	Enhancements	replacement of existing station building or property assets
Distribution Assets	• Sustainment of discreet distribution assets based on assessed condition (Health Index) and prioritization (See Section 2.1 Asset Management Process Overview)	Planned Pole Replacement	• Planned replacement or upgrade of HOL owned poles or cross-arms based on condition assessment; • Pole attachments and conductors are considered in scope for replacement along with the poles/cross-arms where they are of the same vintage as the poles
		Insulator Replacement Program	• Replacement or upgrade of HOL owned insulators that have been deemed a safety hazard, operationally inadequate and/or may cause pole fires
		Elbow & Insert Replacement	• Replacement and upgrade of distribution transformer non-vented elbows and/or inserts on the 27.6 kV system due to safety concerns of flash over during operation below $0^{o}C$

		Distribution Transformer Replacement	• Replacement of overhead or underground distribution transformers due to functional, safety or environmental concern (leaks, PCBs, corrosion, failure risk, etc.), or upgrade, including transformer shop testing and commissioning
		Vault Rehab or Rebuild	• Vault rehabilitation due to condition of equipment or removal for consolidation or system betterment; • Includes replacement of Jack-Bus arrangements; • Exclusive of work considered under Plant Relocation & Upgrade
		Civil Rehabilitation	• Rehabilitation or rebuild of underground cable chambers, collars, ducts, and equipment pads due to condition or failure risk; • Includes installation of pads and vault space under pads; • Duct extensions considered under Line Extensions
		Cable Replacement	• Replacement or injection of underground cable based on condition;

			• All cable types considered, i.e. PILC, XLPE, butyl rubber, etc.; • Can include associated distribution transformer replacements based on condition assessment on a case-by-case basis
		Switchgear New & Rehab	• Replacement, refurbishment or upgrade of HOL owned switchgear based on condition
		O/H Equipment New & Rehab	• Installation of new, or the rehabilitation of overhead equipment (i.e. switches, reclosers, cutouts, or arrestors) based on condition or functional requirements (i.e. upgrade to gang operable switches or automated devices)
		Distribution Plant Failure	• Unplanned replacement of failed distribution assets; • In cases where there is no full functional failure (causing an interruption), or immediate safety or environmental concern then work should be planned and prioritized based on crew and resource availability (where work is not considered to be an

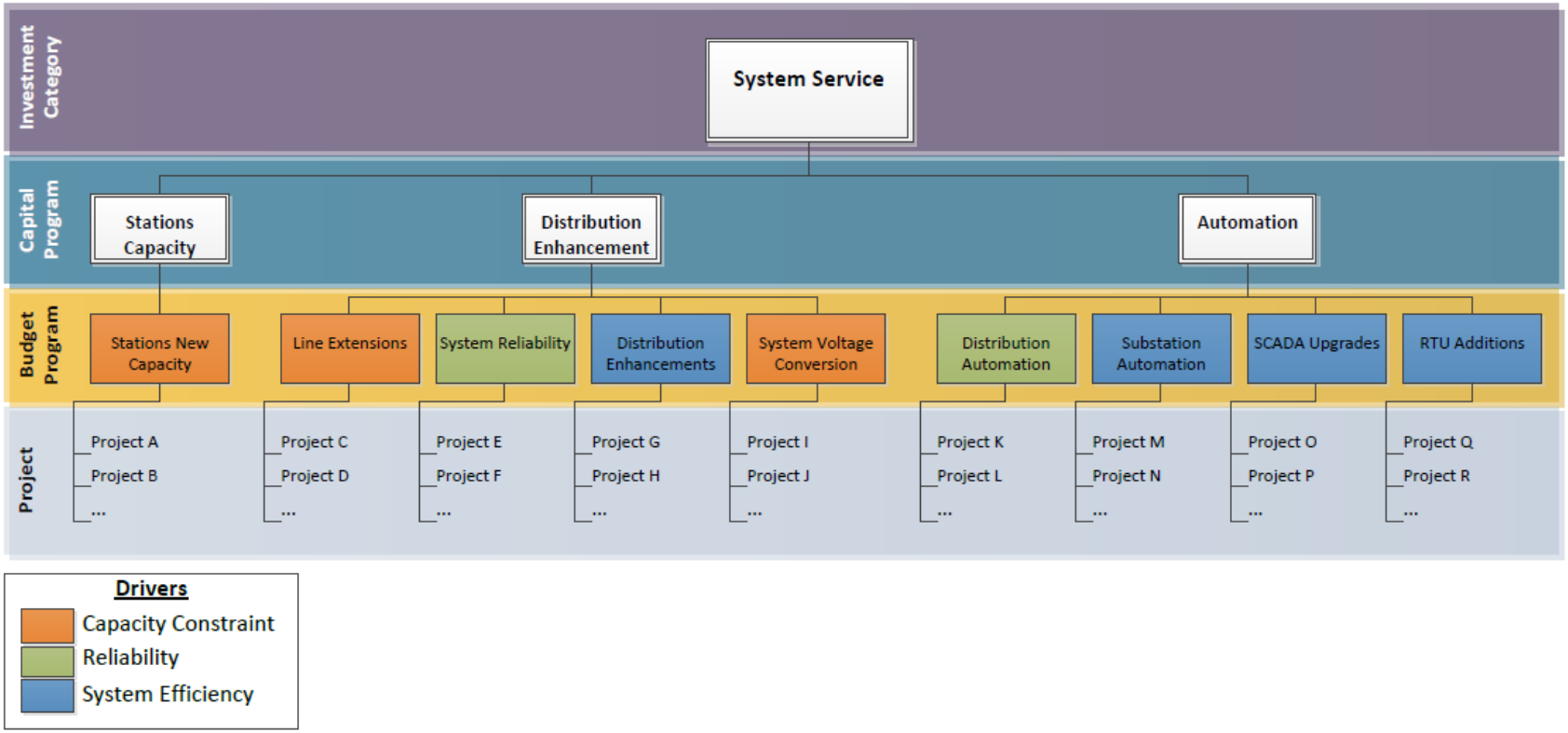
			emergency); • If the equipment has been damaged by a third party then it is considered under Damage to Plant
Metering	• Upgrading customer meters for the ability to remotely disconnect and reconnect	Remote Disconnected Smart Meter	• Upgrading customer meters for the ability to remotely disconnect and reconnect

1

3.1.3 System Service

System Service investments, as defined in Chapter 5, Section 5.1.1 Investment Categories are "modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements". Figure 3.1.3 shows the System Service financial hierarchy and drivers.

Figure 3.1.3 - System Service Financial Hierarchy and Drivers



1 **Table 3.1.4 - System Service Capital Program & Budget Program Descriptions**

Capital Program		Budget Program	
Name	**Description**	**Name**	**Description**
Stations Capacity	• Increase in station capacity by either increasing existing station transformation or through the construction of new substations; • Identified through the Asset Management Process (see 2.1.2.1.3 System Service) for the purpose of ensuring adequate and reliable supply	Stations New Capacity	• New stations or increased station transformation through transformer upgrades or additions at existing stations as identified through the Capacity Planning process
Distribution Enhancement	• Modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability, power quality or for relieving system capacity constraints as identified through the Asset Management Process (see 2.1.2.1.3 System Service)	Line Extension	• Line extensions (overhead or underground) for the purpose of increased capacity, reliability and/or improved power quality as identified through either the Reliability or Capacity planning processes
		System Reliability	• Specific enhancements to particular areas identified as having poor historic system reliability, as identified through the Asset Management

			Process (see 2.1.2.1.3 System Service); • Includes projects to support the betterment of the Worst Performing Feeders (see 1.3.1.1.3 Worst Feeder Analysis)
		Distribution Enhancements	• Modifications to an existing distribution system made for purposes of improving system operating characteristics or operability (e.g. circuit reconfiguration)
		System Voltage Conversion	• Distribution voltage conversion for increased capacity in areas seeing significant growth; • Typically coincide with retirement of existing stations or distribution assets due to condition or failure risk
Automation	• Installation and commissioning of automated equipment for the purposes of communication or operability	Distribution Automation	• Installation of remotely operable or intelligent overhead or underground equipment, i.e. fault current indicators, Vipers, VBMs, SCADA operable switchgear, etc.

		Substation Automation	• Automation of non-operational information and functionality (not SCADA)
		SCADA Upgrades	• Upgrades to the Supervisory Control and Data Acquisition (SCADA) system; • Both hardware and software upgrades are considered
		RTU Additions	• Upgrading and addition of Remote Terminal Units (RTUs) in the distribution network to improve SCADA functionality

1

3.1.4 General Plant

General Plant investments, as defined in, Chapter 5, Section 5.1.1 Investment Categories are "modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities". Figure 3.1.4 shows the General Plant financial hierarchy and drivers.

Figure 3.1.4 - General Plant Financial Hierarchy and Drivers

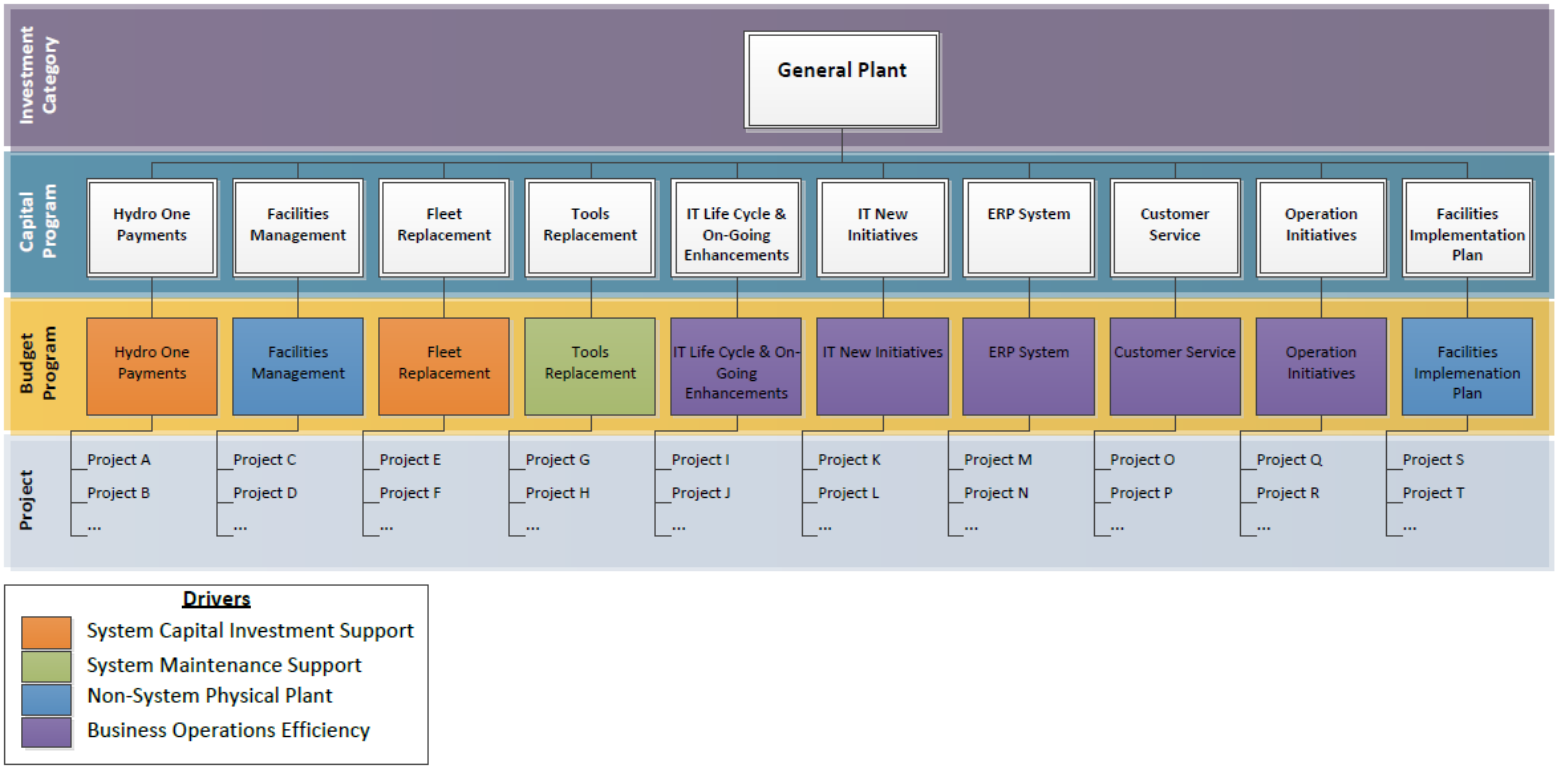


Table 3.1.5 - General Plant Capital Program & Budget Program Descriptions

Capital Program		Budget Program	
Name	**Description**	**Name**	**Description**
Hydro One Payments	Capital contributions to intangible assets purchased from Hydro One in conjunction with HOL's major station projects. Generally referred to as CCRA.	Hydro One Payments	Capital contributions to intangible assets purchased from Hydro One in conjunction with HOL's major station projects. Generally referred to as CCRA.
Facilities Management	The program addresses the necessary building improvements for the admin buildings and the operation centres to ensure employees with a safe environment to operate.	Facilities Management	The program addresses the necessary building improvements for the admin buildings and the operation centres to ensure employees with a safe environment to operate.
Fleet Replacement	Acquisition of vehicles to replace end of life vehicles. Program objective is to provide safe, reliable and efficient vehicles to meet the operational requirements.	Fleet Replacement	Acquisition of vehicles to replace end of life vehicles. Program objective is to provide safe, reliable and efficient vehicles to meet the operational requirements.
Tools Replacement	Tools replacements are needed to carry out the distribution maintenance and capital program efficiently and effectively.	Tools Replacement	Tools replacements are needed to carry out the distribution maintenance and capital program efficiently and effectively.
IT Life Cycle & On-Going	The program addresses the renewal and maintenance of	IT Life Cycle & On-Going	The program addresses the renewal and maintenance of

Enhancements	the IT infrastructure including PC replacements, network security, data loss prevention program, network switches upgrade, network file storage, and software licenses.	Enhancements	the IT infrastructure including PC replacements, network security, data loss prevention program, network switches upgrade, network file storage, and software licenses.
IT New Initiatives	The program focuses on initiatives to optimize business operations including Document Management System, Enterprise Architecture Program, and Data Management System	IT New Initiatives	The program focuses on initiatives to optimize business operations including Document Management System, Enterprise Architecture Program, and Data Management System
ERP System	The ERP is a vital technology solution to achieve business outcomes. Hydro utilizes J.D. Edwards (JDE) as its enterprise resource planning system. It is used to manage budgets, procurement, inventory, payroll, job cost, and general ledger functions.	ERP System	The ERP is a vital technology solution to achieve business outcomes. Hydro utilizes J.D. Edwards (JDE) as its enterprise resource planning system. It is used to manage budgets, procurement, inventory, payroll, job cost, and general ledger functions.
Customer Service	The program includes the Customer Care and Billing system, Customer Service Strategy, and Website Enhancements. The	Customer Service	The program includes the Customer Care and Billing system, Customer Service Strategy, and Website Enhancements. The program

	program objective is to add value to the customers.		objective is to add value to the customers.
Operation Initiatives	The program objective is to strengthen the Geospatial Resource Management (GRM) system, enhance reliability services, and increase productivity and organizational effectiveness.	Operation Initiatives	The program objective is to strengthen the Geospatial Resource Management (GRM) system, enhance reliability services, and increase productivity and organizational effectiveness.
Facilities Implementation Plan	The expenditures related to the purchase of two parcels of land upon which HOL will construct its new Eastern Operations & Campus and its Southern Operations centre and warehouse facilities	Facilities Implementation Plan	The expenditures related to the purchase of two parcels of land upon which HOL will construct its new Eastern Operations & Campus and its Southern Operations centre and warehouse facilities

3.1.5 Load and Generation Connection Capability

This section summarizes HOL's capability to connect new load or generation. More details are found in the System Capacity Plan section of the 2014 Annual Planning Report, in Attachment B-1(B).

3.1.5.1 Ability to Connect New Load

HOL regularly assesses the capability and reliability of the distribution system in an effort to maintain adequate and reliable supply to customers. Where gaps are found, appropriate plans for additions and modifications consistent with all regulatory requirements and with due consideration for safety, environment, finance and supply system reliability/security are developed.

In this regard, the supply needs have been assessed to determine if additions and/or modifications are required to maintain an adequate and reliable/secure system capacity.

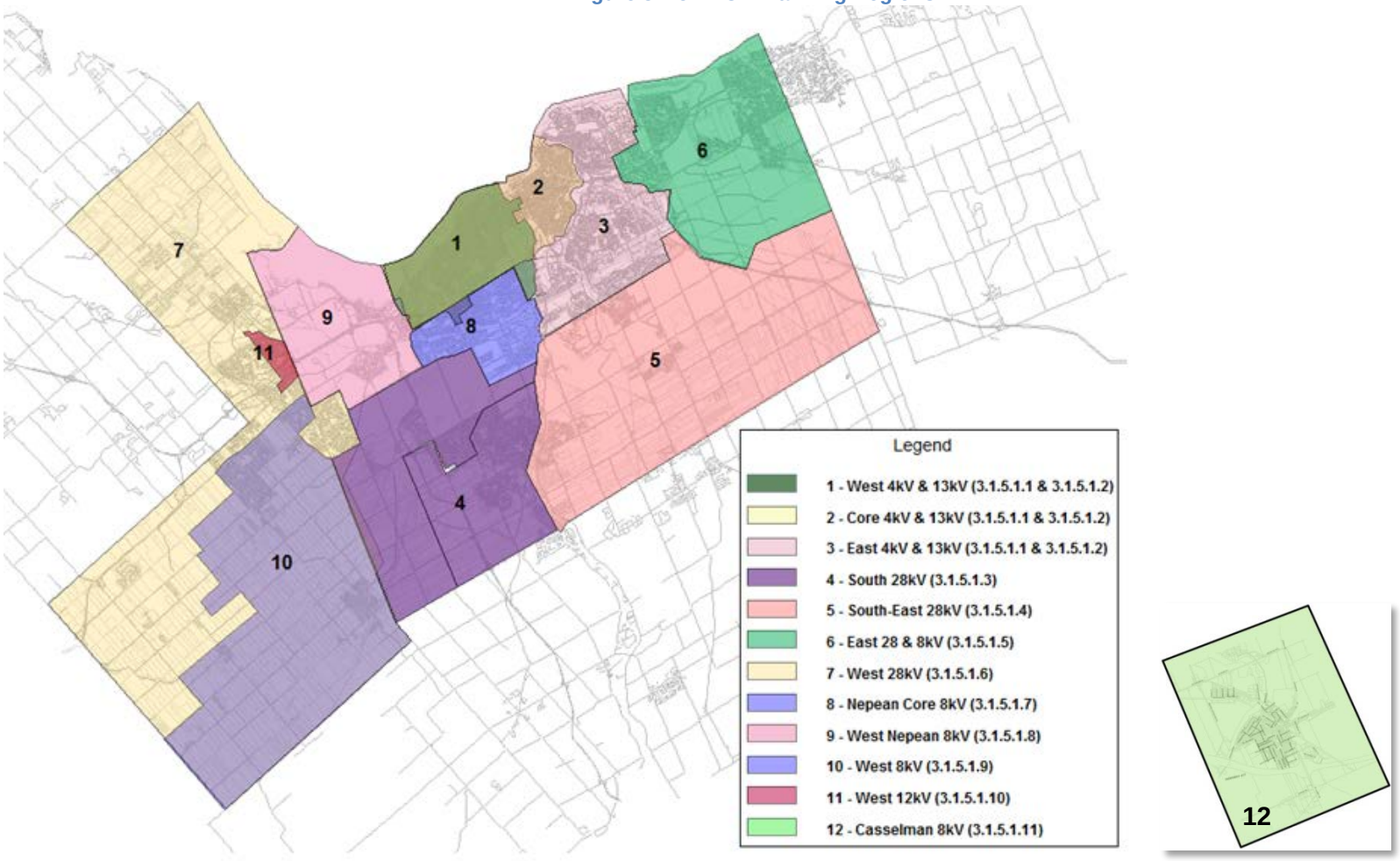
HOL plans system and feeder capacity based on coincident peak loading and single (N-1) contingency. The station and area contingency is considered to be the loss of the largest element, typically either a substation transformer or supply circuit. Under a single contingency, the system is planned to maintain the loading within the remaining equipment's top rating (either 10 day Limited Time Rating (LTR) or allowable flat rating). HOL plans a one-to-one backup arrangement for feeders, this means that circuits have contingency pairs so that for the loss of any one circuit the entire load can be recovered by its back-up thereby reducing the number of switching operations (and time) for recovery of full load. With this arrangement any one circuit must only be loaded to half of its 8 hour emergency rating. Refer to section 1.3.1.4 System Operations Performance for more details on the determination of planning and rated capacities for stations and feeders.

Load for each substation supplying HOL customers is forecasted separately using the previous year's summer coincident peak as the starting point for the forecast. An average annual load growth rate is calculated using the station's historic load levels. This rate is used to predict the baseline load growth over the next twenty years, and reflects typical addition of new customers and the load maturation of existing customers. Additional adjustments are made to the forecast to account for known City of Ottawa and developer plans, forecasted load transfers and other local events that are expected to impact the load forecast. Loading is weather normalized and a one in ten year heat wave adjustment is used as a worst case planning scenario.

Growth in the City is currently being driven by new residential developments in previously rural areas, infill and intensification in many established areas, as well as major projects like the Ottawa Light Rail Transit (OLRT) system.

HOL distribution system is composed of several subsystems, which are segregated by operating voltage, geographical boundaries, and historic political boundaries (see Figure 3.1.5 - HOL Planning Regions). Each of these subsystems undergoes an extensive review annually, as part of the Capacity Planning Process (Section 2.1.2), and a forecast is produced over a twenty year horizon. The following sections details the forecasted subsystem needs.

Figure 3.1.5 - HOL Planning Regions



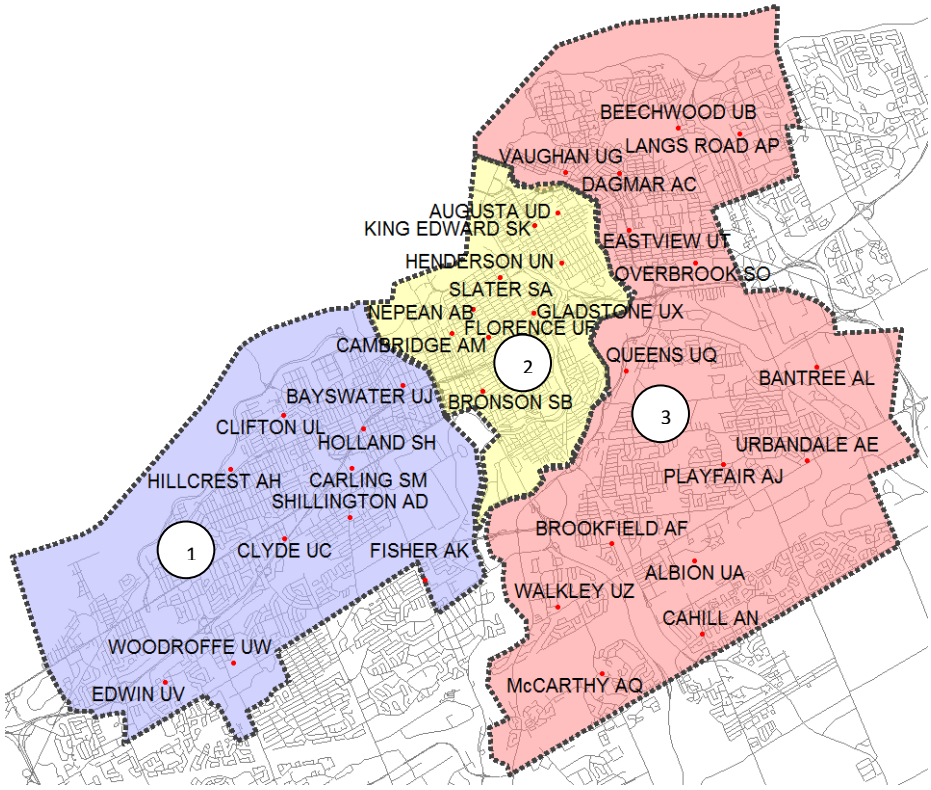
3.1.5.1.1 4 kV System

HOL 4kV supply region (Figure 3.1.6) is comprised of three main areas:

1) The West 4kV supply region covers West of Rochester Street, East of Bayshore Drive, and North of Baseline Road. This region is supplied by the Edwin UV, Shilington AD, Fisher Park AK, Clyde UC, Carling SM, Holland SH, Hillcrest AH, Clifton UL, Bayswater UJ.
2) The Core 4kV supply region covers East of Rochester Street and is bounded West and North of the Rideau River. This region is supplied by the Bronson SB, Nepean AB, Gladstone UX, Augusta UD, Cambridge AM, Slater SA, Henderson UN, Florence UF, Riverdale SR, King Edward SK.
3) The East 4kV supply region covers West of Blair Road, East of the Rideau River, and North of Hunt Club Road. This region is supplied by the Vaughan UG, Bantree AL, Albion UA, Eastview UT, Playfair AJ, Cahill AN, Dagmar AC, Urbandale AE, McCarthy AQ, Beechwood UB, Brookfield AF, Walkley UZ, Queens UQ, Langs Road AP, Overbrook SO, Church AA.

These 4kV substations are supplied from twelve 13kV stations and provide electricity for much of the residential load in the region (See 3.1.5.1.2 13kV System).

Figure 3.1.6 - 4kV Supply Region



Through the Official Plan, the City of Ottawa is promoting new growth by means of intensification. Many new developments are converting from low-rise apartments to larger high density condos and apartment buildings. As a result, most of the 4kV substations are experiencing decreasing loads as customers upgrade their electrical supply and transfer to being supplied directly from the 13kV system.

This decrease in load among the stations reduces their financial usefulness due to the fixed maintenance and replacement costs required that is independent of load. In areas that have seen a large transition of their load being supplied by 13kV stations and where the 4kV substation's equipment is nearing end of life, it may be financially advantageous to convert the existing customers to a 13kV supply while decommissioning the 4kV substation.

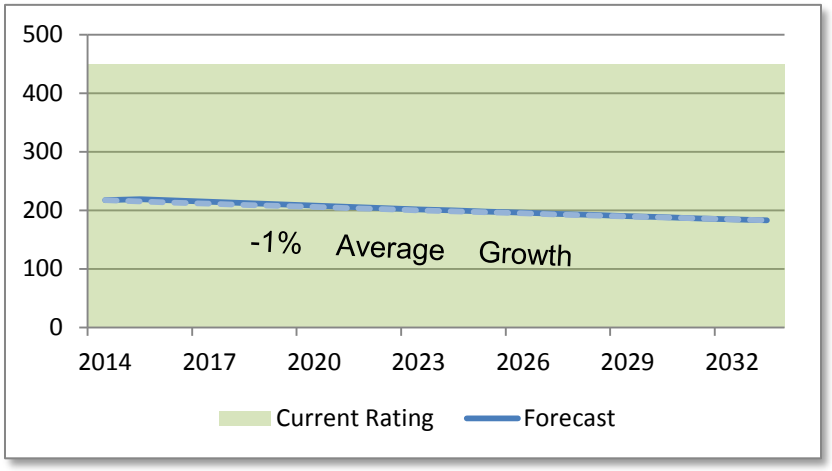
Currently, HOL is undergoing a voltage conversion project where the 4kV system fed from the substation Woodroffe UW is being decommissioned. The customers that were supplied from this system are being transitioned to the 13kV system fed from Woodroffe TW. This project was

mainly driven by the Woodroffe UW assets nearing their end of life, but also due to the decreasing load on the substation. A business case was developed concluding that it made financial sense to undergo the voltage conversion. The end date of this project will be December 2015.

Stations which are forecasted to have diminished asset utilization due to decreased load are identified as potential candidates for voltage conversion projects. Stations for consideration in the short term include: Slater SA and Cahill AN. These stations were identified based on their loading, however, detailed business cases will be required to ultimately determine whether a voltage conversion makes economic sense.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.7.

Figure 3.1.7 - 4kV Load Forecast



Capacity Projects

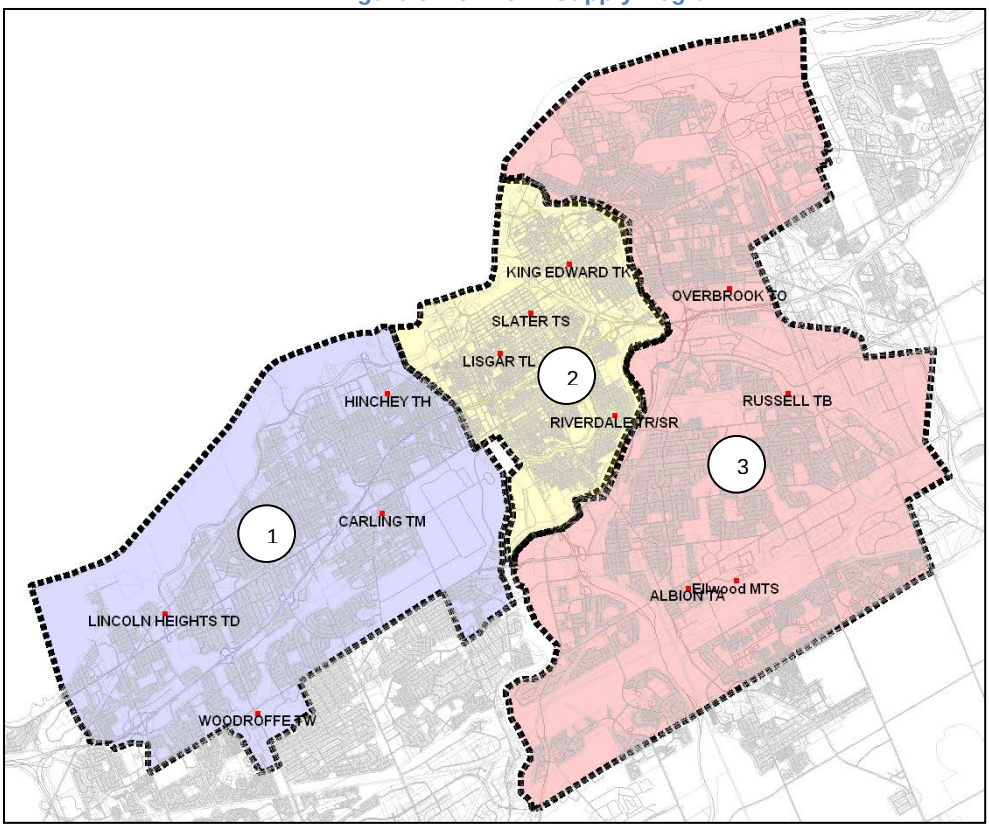
None

3.1.5.1.2 13kV System

The HOL 13kV supply region is composed of 3 main areas, as shown in Figure 3.1.8. These zones correspond to the 4kV system mentioned in 3.1.5.1.1 above. The three areas are:

1. The West 13kV supply region covers from Bayview Yards and west of Preston Street to Bayshore Drive, north of Baseline Road. This region is supplied by Hinchey TH, Carling TM, Woodroffe TW and Lincoln Heights TD. Hinchey TH also supports the Core 13kV supply region.
2. The Core 13kV area follows the Rideau River to the East and covers to LeBreton Flats in the West. This region is supplied by King Edward TK, Slater TS, Lisgar TL, Hinchey TH, and Riverdale TR. Riverdale TR and King Edward TK also support the East and Core 13kV supply regions.
3. The East 13kV supply region includes the eastern portion of the Old City of Ottawa. This region is supplied by the Russell TB, Albion TA, Ellwood TS, Overbrook TO, Riverdale TR and King Edward TK. Riverdale TR and King Edward TK also support the East and Central 13kV supply regions.

Figure 3.1.8 - 13kV Supply Region



Much of the residential load in these regions is not directly supplied from the 13kV system, but rather from a total of thirty-five 4kV substations (see 3.1.5.1.1 4 kV System) which are supplied from the 13kV system.

Through the Official Plan, the City of Ottawa is promoting new growth by means of intensification. This impacts the 13kV system as it covers mostly established areas. Many new developments are trading in low-rise apartments for larger, high density condos. This will reduce the load of the 4kV network through conversion onto the 13kV system.

The majority of the load growth on the 13kV system is from new infrastructure projects and City driven Community Design Plans. More detailed information can be found in Appendix E.

- The West 13kV new loads include the Ottawa Light Rail Transit (OLRT), Tunney's Pasture, Bayview Yards, Centrepointe, Richmond Road, and Preston-Carling Area.

- The Core 13kV is seeing large new loads such as the Ottawa Light Rail Transit (OLRT), the Cliff Street Heating/Cooling Plant (CHCP), Lansdowne Park, LeBreton Flats, Bayview Yards and Transit Oriented Development (TOD).
- The East 13kV new loads include the Ottawa Light Rail Transit (OLRT), the reconstruction of Rockliffe CFB, Transit Oriented Developments (TOD), the Bank Street CDP and the Beechwood CDP.

In the short term, there is a requirement for capacity upgrades and the construction of station interconnections to transfer load at opportune times in order to manage the growth. Longer term planning relating to the IRRP is meant to deal with transmission upgrade plans.

Major capacity infrastructure upgrades on this system include the Hinchey TH Expansion, the Lisgar TL Upgrade, the Overbrook TO upgrade, the King Edward TK upgrade, and the Russell TB upgrade.

Hinchey TH Expansion

The capacity expansion of Hinchey TH substation began in 2012. The two transformers at Hinchey TH will have their tertiary winding brought out and allow for the installation of a new bus. The capacity at Hinchey TH will increase from 42 MVA to 99 MVA and will provide 12 new breaker positions. The project is expected to be completed in 2015. Feeder expansions out of Hinchey TH will also be required to transfer load from Lisgar TL to accommodate new growth. Currently 4 feeder expansions are planned for 2014-2015, more will proceed as necessary.

Hinchey TH is currently limiting generation connection capacity based on its minimum load. This expansion will allow for increased generation capacity by providing the ability to transfer more load to the station, plus, the nature of the power transformers will allow some reverse flow capability.

Lisgar TL Upgrade

To accommodate the new load to the west of downtown, upgrading the capacity at Lisgar TL is required to support Hinchey TH. This project will increase the limited time rating (LTR) capacity from 83 MVA to 133 MVA. HONI is currently working on preparing estimates for this work.

This upgrade will allow for increased generation capacity availability by upgrading the equipment capacity which currently has a thermal restriction for any new generation connections.

Overbrook TO Upgrade

The total transformer capacity at Overbrook TO will be upgraded to 144MVA from 82MVA. The transmission supply to the substation will need to be upgraded to facilitate the increased capacity of this station. This is currently being studied under the IRRP being conducted by HONI, HOL and the OPA (now IESO). This upgrade will be required in or about 2016.

King Edward TK Upgrade

The two transformers at King Edward TK substation are currently mismatched in capacity, limiting the overall available capacity. This project would see the replacement of the undersized transformer thereby increasing the available LTR of the station from 80 MVA to 136 MVA. The increased capacity will relieve Slater TS and support the Light Rail Transit (LRT) project. The timelines for this project may be affected by the on-going IRRP with the OPA (now IESO) and Hydro One. The study is currently reviewing the A4K 115kV transmission line which has been identified as having a thermal overload in N-1 contingency loss of the A5RK. The project need has been identified for 2021.

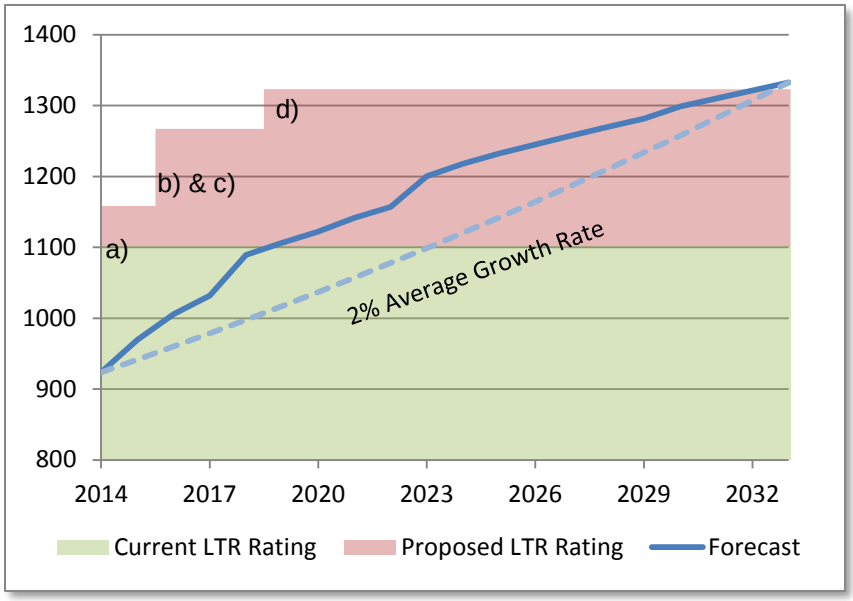
King Edward TK is currently limiting generation connection capacity based on its minimum load. This expansion will allow for increased generation capacity by providing the ability to transfer more load to the station. Also, generation connection capacity can be increased if the power transformers are specified for reverse flow capability.

Russell TB Upgrade

Russell TB will need to be upgraded to 144MVA from the current 77MVA. There are no known transmission limitations that should cause delays in this project and will be required in or about 2024.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.9.

Figure 3.1.9 - 13kV Load Forecast



Capacity Projects

Committed:

(a) Hinchey TH – 57MVA (2014)

Planned:

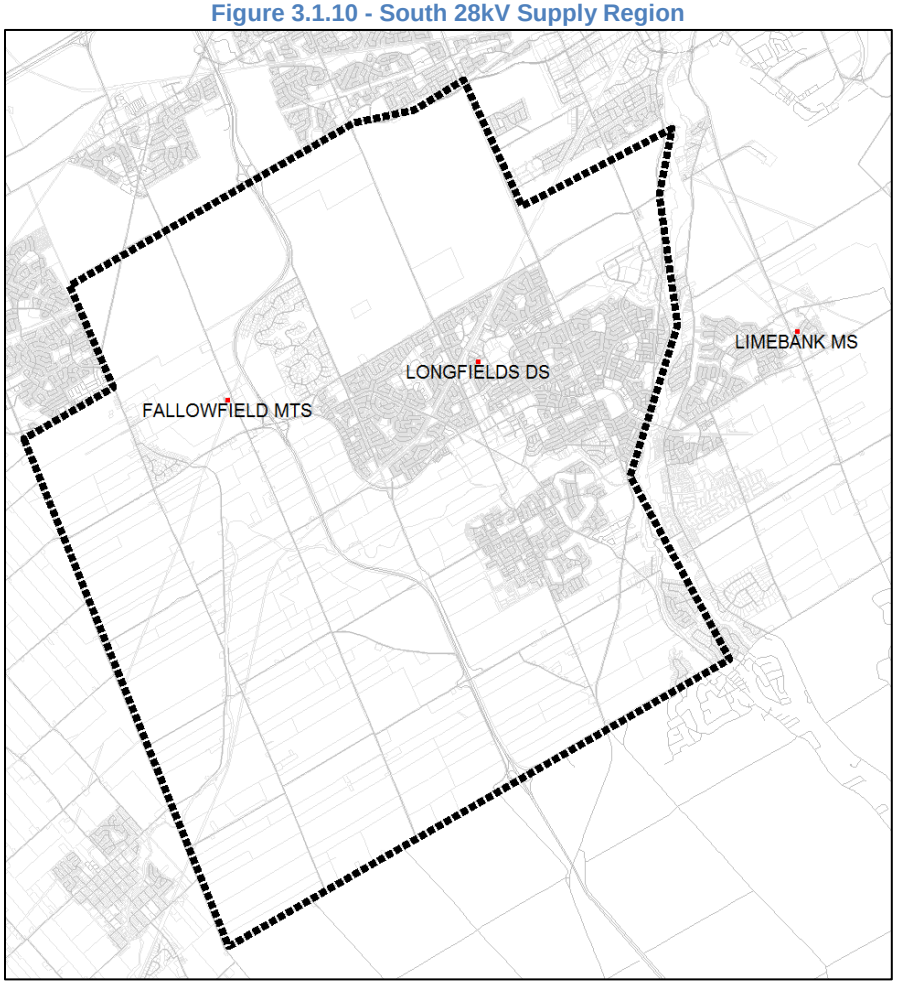
(b) Lisgar TL – 53MVA (2016)
(c) Overbrook TO – 55.6MVA (2016)
(d) King Edward TK – 56MVA (2019)
(e) Slater TS – 50MVA (2025)

1

3.1.5.1.3 South 28kV System

The South 28kV supply region includes the southern portions of Nepean. This region is supplied by the Fallowfield DS and Longfields DS 28kV substations as well as two feeders from Limebank MS 28kV substation, located in the South-East supply region. Figure 3.1.10 shows the supply region of the South 28kV System.

Figure 3.1.10 - South 28kV Supply Region



Despite the physical barrier of the Rideau River between Nepean and Gloucester, the Limebank MS station plays an essential role in supplying both sides of the river.

Growth in the south supply region is driven by the ongoing expansion of suburban residential developments, the Nepean Town Centre and the Strandherd Business Park. In addition, rural areas south of the Jock River which are currently fed by the 8KV system will be transferred to

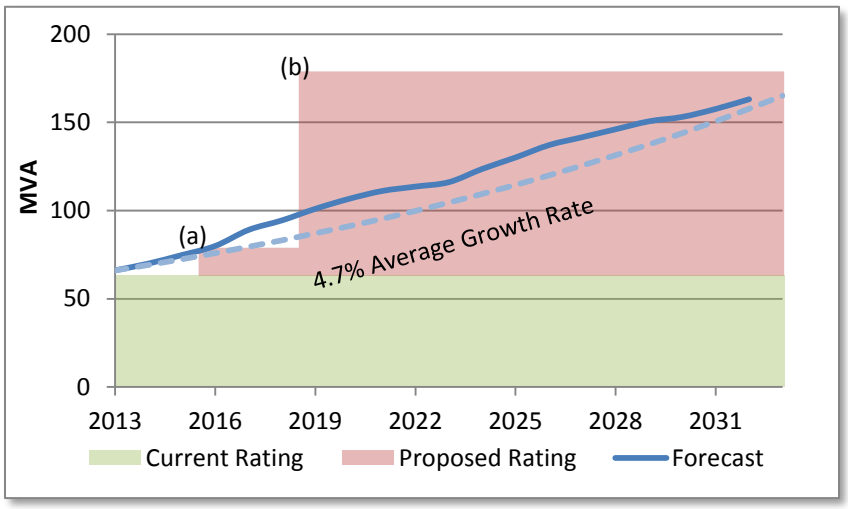
the 28kV system as 28kV feeders are introduced in the area to supply new suburban developments.

Overall, the existing south 28kV area is supplied by a strong network of trunk feeders. However, there is the need to expand the system to cover areas seeing growth, as well as strengthen the interconnections to the south of the Jock River. These issues will be addressed by the introduction of a new substation that will support the growth in the Fallowfield DS supply area for the expected load growth.

Based on the projected load growth, an additional station is required to supply the expected load in the South 28kV area. It is planned to build the new station with 2 X 75 MVA transformers with a need date of 2019. The planned new station will solve the overloading issues in normal operating conditions as well as the N-1 contingency situations to the end of the study period. Currently, capacity in this area is being evaluated under the Regional Planning Study which evaluated the various options to meet the capacity needs and resulted in the next step of determining the location of the new station and transmission connection. Details can be found in the project business case found in Attachment B-1(A).

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.11.

Figure 3.1.11 - South Nepean 28KV load forecast



Capacity Projects

Planned:

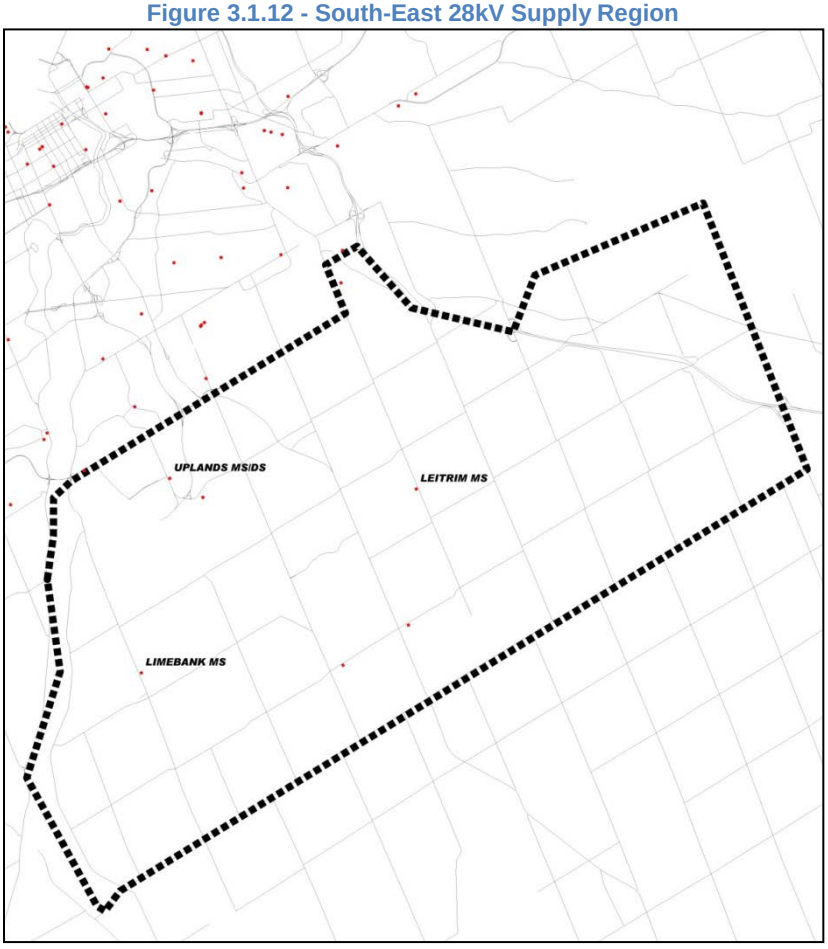
(a) Added Capacity from Limebank- 16MVA(2016)

(b) New 28kV Station – 100 MVA (2019)

3.1.5.1.4 South-East 28kV System

The South-East 28kV supply region includes the southern portions of Gloucester. This region is supplied by the Limebank MS, Uplands MS and Leitrim MS 28kV substations, as well as a small pocket supplied by 8kV feeders from the Hydro One owned South Gloucester substation. Despite the physical barrier of the river between Nepean and Gloucester, the Limebank MS station plays an essential role in supplying both sides of the river, creating interdependence between the South 28kV and the South East 28kV systems. Figure 3.1.12 shows the supply region of the South-East 28kV System.

Figure 3.1.12 - South-East 28kV Supply Region



New load growth in this area is driven by commercial development in the land surrounding the airport and residential and mixed-use developments in the Riverside South and Leitrim community areas.

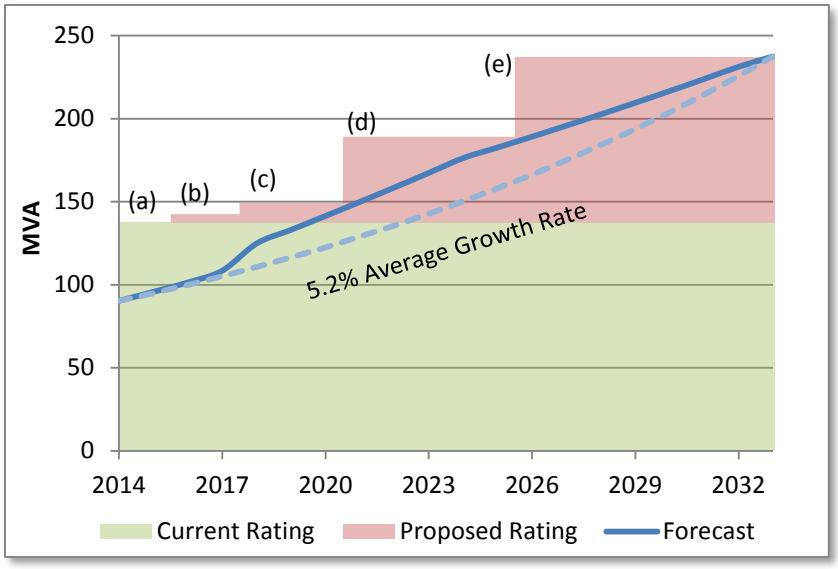
Both Uplands MS and Leitrim MS substations have single supplies and single transformers. With such configurations it is paramount that sufficient distribution circuit ties are maintained to transfer load to adjacent stations under contingency. Circuit ties exist for Uplands MS, although station capacity is currently a limitation to adequately backup capacity for the loss of transformers or supply at Uplands MS.

Regional capacity will require significant increase in order to keep pace with forecasted growth. Upgrades are currently underway at Limebank MS to add a third transformer and make provisions for a fourth transformer, currently projected to be required between 2018 and 2021. In or about 2018, Uplands MS will require an additional transformer to support growth in the region as well. Supply capacity in the region is anticipated to lag growth through the second half of the planning period. The load growth during this period is expected to be met by planned additional upgrades in the South 28kV Region.

While it only results in minor increases to the overall firm capacity in the area, additional transformers are required at both Leitrim MS and Uplands MS in 2016 and 2018 respectively. These units will improve the specific region contingencies and station capacity. As load continues to grow in the Leitrim MS supply area the potential of creating a new transmission connected substation should be evaluated as the existing 44kV supply is limited and it will be costly to add a second 44kV supply.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.13.

Figure 3.1.13 - South East Load Growth



Capacity Projects

Committed:

(a) Limebank MS – 40MVA (2014)

Planned:

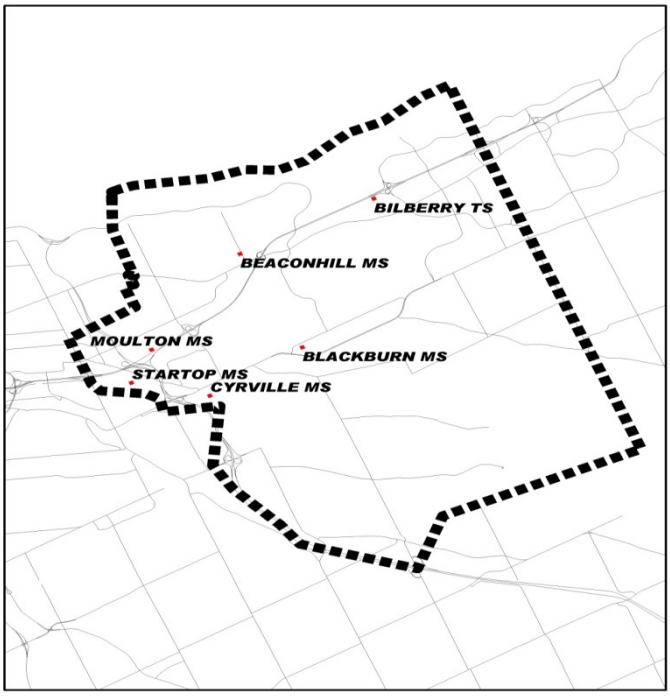
(b) Leitrim (2nd Tx) – 5 MVA (2016)
(c) Uplands (2nd Tx) – 40MVA (2018)
(d) Limebank MS – 46MVA (2021)
(e) South 28kV Support (2026)

1

East 8kV & 28kV System

The East 28kV and 8kV supply area is bounded by the old Gloucester & Ottawa municipal boundary and Highway 417 in the south. Supply to the region includes 28kV transmission connected stations: Cyrville MTS, Bilberry TS and Moulton MS as well as 44kV sub transmission supplied 8kV substations: Startop MS, Blackburn MS and Beaconhill MS. Figure 3.1.14 shows the supply region of the East 28kV and 8kV System.

Figure 3.1.14 - East 28kV and 8kV Supply Region



The East 28/8kV system is seeing two main pockets of growth: the East Urban Community, a combination of residential and mixed-use areas, and Light Rail Transit related load developing in the vicinity of the split between highways 417 and 174.

The 28kV & 8kV trunk network provides acceptable coverage of the region; however, expansion of the Cyrville MTS trunk circuits to the east (currently underway) will be required to supply the south of Orleans as it develops.

From a regional point of view there is sufficient capacity to address forecasted load growth. Minor changes to address localized load growth will be required over the next 20 years.

Startop MS Transformer Upgrades

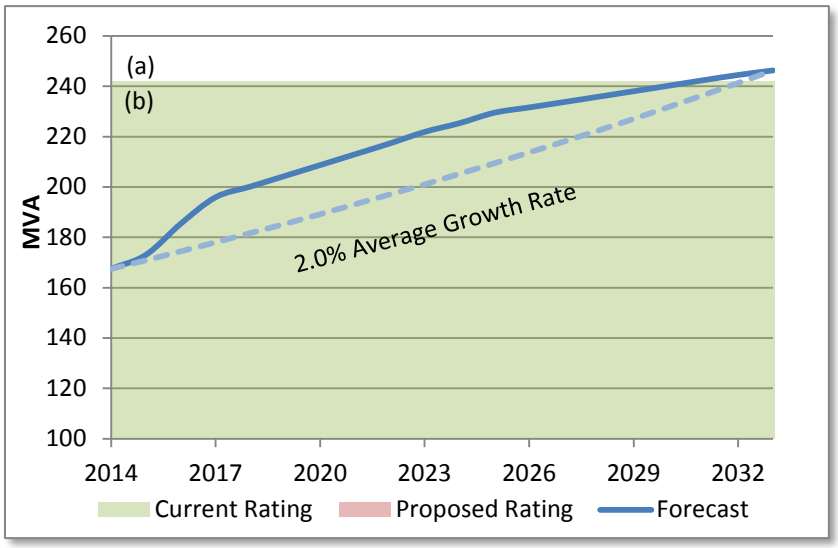
While overall regional capacity is sufficient for future load growth, the local loading on the Startop MS substation is currently above the station rating. Due to the distance between substations this load cannot be effectively supplied from the other 8kV stations in the area. The upgrade of these transformers will be coordinated with primary protection upgrades and automation work occurring on the 44kV subtransmission in the east. The new station transformers will increase the station capacity from 15MVA to 20MVA and will be completed in 2015.

HONI Orleans TS Construction

HONI is constructing a new 28kV station, Orleans TS, in the vicinity of Mer Bleue Road and Innes Road. HOL has requested ownership of a single circuit, providing for 16MVA of capacity. The new Orleans TS feeder will tie into the system currently supplied from the Cyrville F1, reducing the load on Cyrville MTS and possibly Bilberry TS and provide additional redundancy to the area. The new feeder will be tied into the Mer Bleue Road line and open points introduced along Renaud Road and Navan Road. It is anticipated that this circuit will be in service in 2015.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.15.

Figure 3.1.15 - East 8kV & 28kV Load Growth



Capacity Projects

Committed:

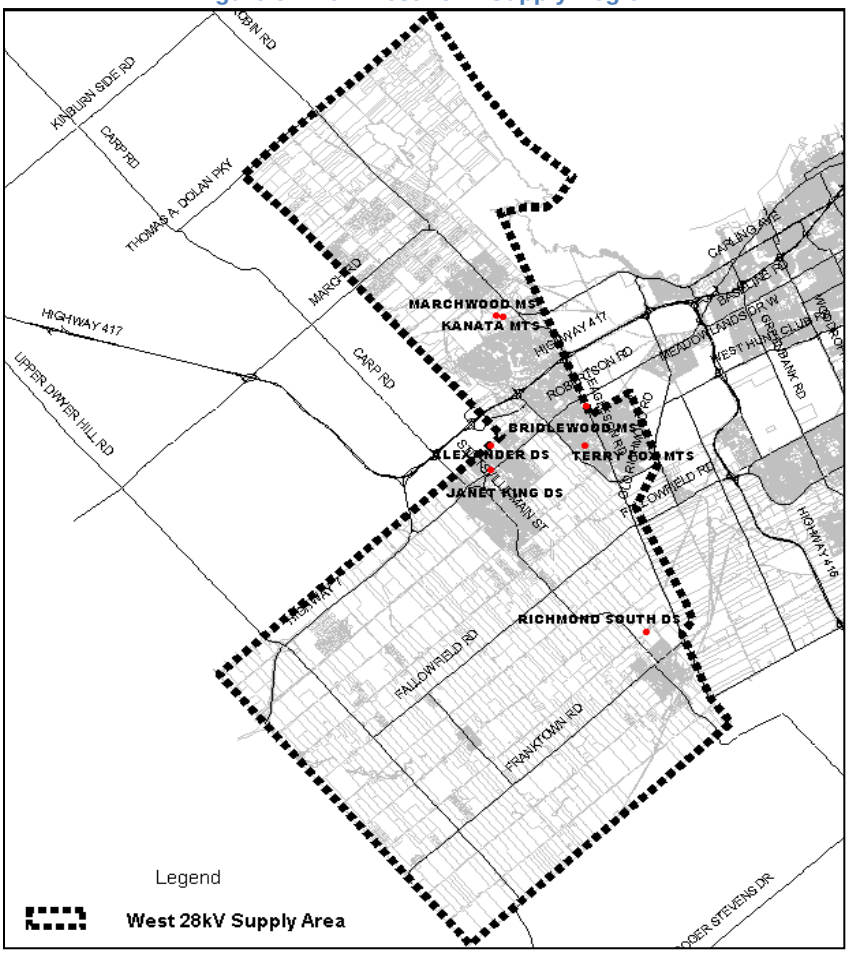
(a) Startop MS – 5MVA (2014)
(b) Orleans TS – 16MVA (2014)

3.1.5.1.5 West 28kV System

The West 28kV supply region includes Kanata and Stittsville. The region is bounded by HOL's service boundary in the west, south and north. Eagleson Road has been utilized as the main boundary to the east, with the exception of the Bridlewood Area. The majority of this service territory is fed at 28kV; however, there are pockets fed at 12kV and 8kV. The 28kV region is supplied by the Kanata MTS, Marchwood MS, Bridlewood MS, Alexander DS, Janet King DS and the Terry Fox MTS 28kV substations.

Figure 3.1.16 shows the supply region of the West 28kV System.

Figure 3.1.16 - West 28kV Supply Region



Growth in the west supply region is driven by the ongoing expansion of suburban residential developments, and associated mixed-use centres.

Projected load growth in the Kanata and Stittsville areas is expected to be supplied from the recent addition to the system, Terry Fox MTS. Terry Fox MTS is located on Michael Cowpland Drive along the 230kV right-of-way and will mainly supply the areas of new growth, and act as a backup for Bridlewood MS and Janet King DS. Terry Fox MTS will also be used to off-load the Stittsville load from the Hydro One owned substation Alexander DS which will allow Hydro One to have available capacity for growth in their service territory.

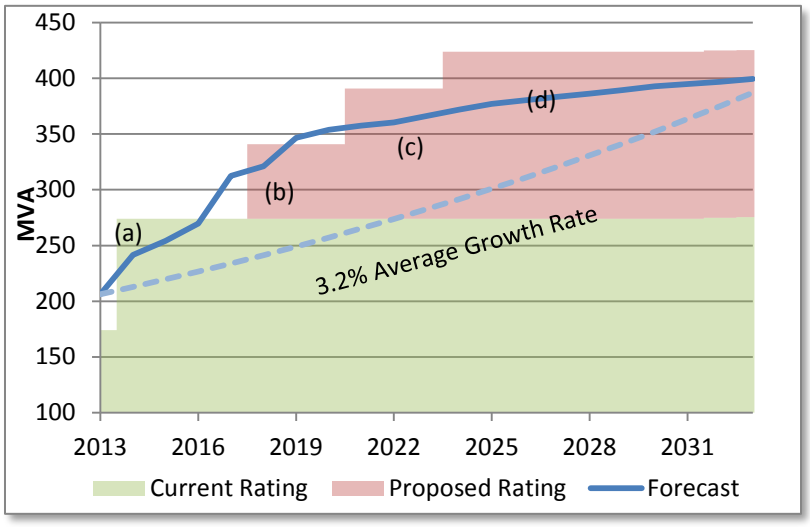
The anticipated growth in the Village of Richmond has prompted the upgrade and voltage conversion of the Richmond South DS substation. Construction is anticipated to begin in 2016 and will increase capacity to accommodate the expected growth and will increase the capacity of Richmond South DS by 1100%.

Overall, the existing west 28kV area is supplied by an adequate network of trunk feeders. There is however the need to expand the system to cover areas seeing growth, as well as to transfer the HOL load off of Alexander DS. Back-up solutions are also required in the south section of the Stittsville community as well as create a backup loop across the south-western part of the region including Richmond. These issues will be addressed by the introduction of six feeders from Terry Fox MTS and the four new feeders planned from Richmond South DS.

There is a need in the short term to increase capacity in the Richmond area as well as increase the transformation at Bridlewood MS and Marchwood MTS to meet the N-1 planning criteria at the station level. Distribution transfer capabilities can however be maintained allowing station transformers to remain below capacity in an N-1 situation delaying the need date for capacity upgrades. Due to the future anticipated capacity demand expected from the Richmond area, Richmond South DS will require an upgrade with voltage conversion to be capable of meeting this demand. The rebuild is planned to replace the existing 8kV transformer with two 28kV 45/60/75 MVA units. Based on the forecasted station growth and the assumed ability to maintain feeder transfer during a station N-1 contingency it is planned to completely rebuild the Bridlewood MS substation by replacing the existing four transformers supplying both 8kV and 28kV, with two 75 MVA units supplying solely 28kV in 2019. In order to maintain supply capacity within the north 28kV supply territory it is planned to replace the 33 MVA transformers at Marchwood MS with 30/40/50 MVA units (with an assumed LTR of 66 – 1.33 x 50) by 2026.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.17.

Figure 3.1.17 - West 28kV Load Growth



Capacity Projects

Committed:

(a) Terry Fox MTS – 100MVA (2014)

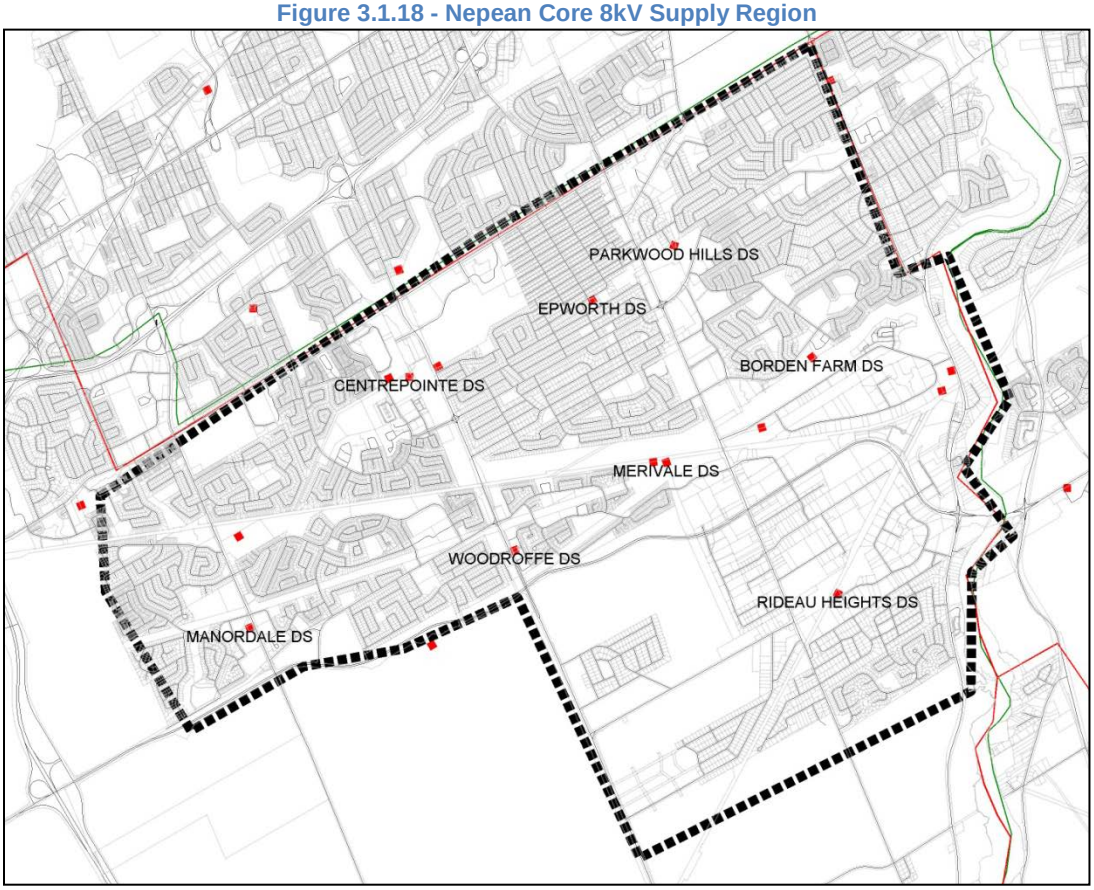
Planned:

(b) Richmond South DS – 67MVA (2016)
(c) Bridlewood MS – 50MVA (2019)
(d) Marchwood MS – 33MVA (2022)

3.1.5.1.6 Nepean Core 8kV System

The Nepean Core 8kV supply region includes the northern portions of Nepean. This region is supplied by the Manordale DS, Centrepointe DS, Woodroffe DS, Epworth DS, Merivale DS, Parkwood Hills DS, Borden Farms DS and Rideau Heights DS 8kV substations. Figure 3.1.18 shows the supply region of the Nepean Core 8kV System.

Figure 3.1.18 - Nepean Core 8kV Supply Region



Growth in the 8kV Nepean supply region is driven by ongoing commercial developments and associated mixed-use centers, two major areas of development are the Nepean Employment Area (located around Hunt Club Road between Merivale Road and Prince of Wales Drive) and Centrepointe that involves the expansion of Algonquin College and the relocation of the existing Transit Station.

The existing 8kV Nepean area is above the capacity limitations. The area of main concern is the Nepean employment area in which the trunk feeders are approaching their capacity limitations and the existing circuit interconnections are limited.

Over the next 20 years, significant growth is expected for the employment area in the Nepean region. The expected growth will push the stations and feeders to their capacity limits. The transformers at Merivale DS and Borden Farm DS are at the end of their useful lifetime, work at Borden Farm is currently in progress and expected to be completed by 2015. By 2021, new 28KV feeders will need to be introduced in this area along Hunt Club Road and Prince of Wales Drive where a high concentration of load is expected. In addition, major circuit reconfiguration and new interconnection ties need to be built in order to maintain a reliable system for this area.

Borden Farm DS Transformers Replacement

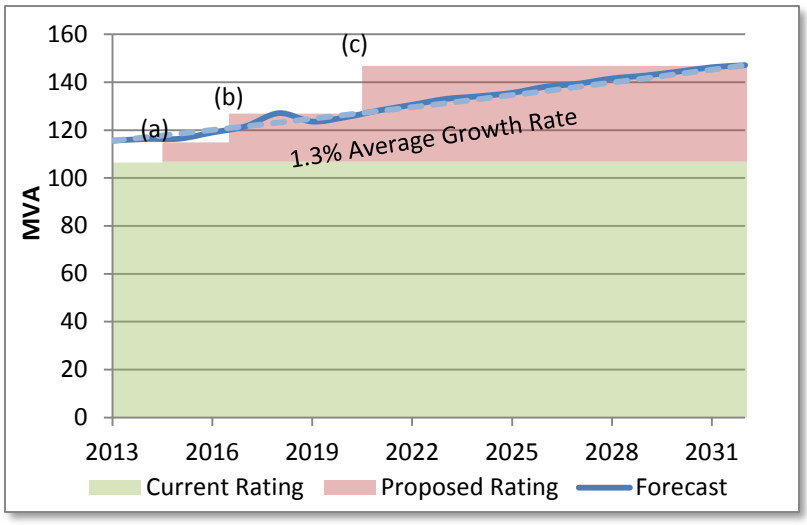
The transformers at this station have reached the end of their life and are in need of immediate replacement. In 2013, a project was started to replace the transformers and it will be completed by 2015. As mentioned in this report, the exiting transformer size would not be able to supply the additional proposed load in the next 8 years. It is recommended that the transformation at the station be upgraded to 2 x 15MVA.

New Merivale DS Station

This station is at the end of its life and it is planned for replacement with design starting in 2015 with completion in ~~2016~~ 2018. Additional capacity is required in order to service the proposed additional load. It is planned that the transformation be upgraded to 2x20 MVA transformers and four feeders per bus.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.19.

Figure 3.1.19 - Nepean 8kV Load Growth



Capacity Projects

Planned:

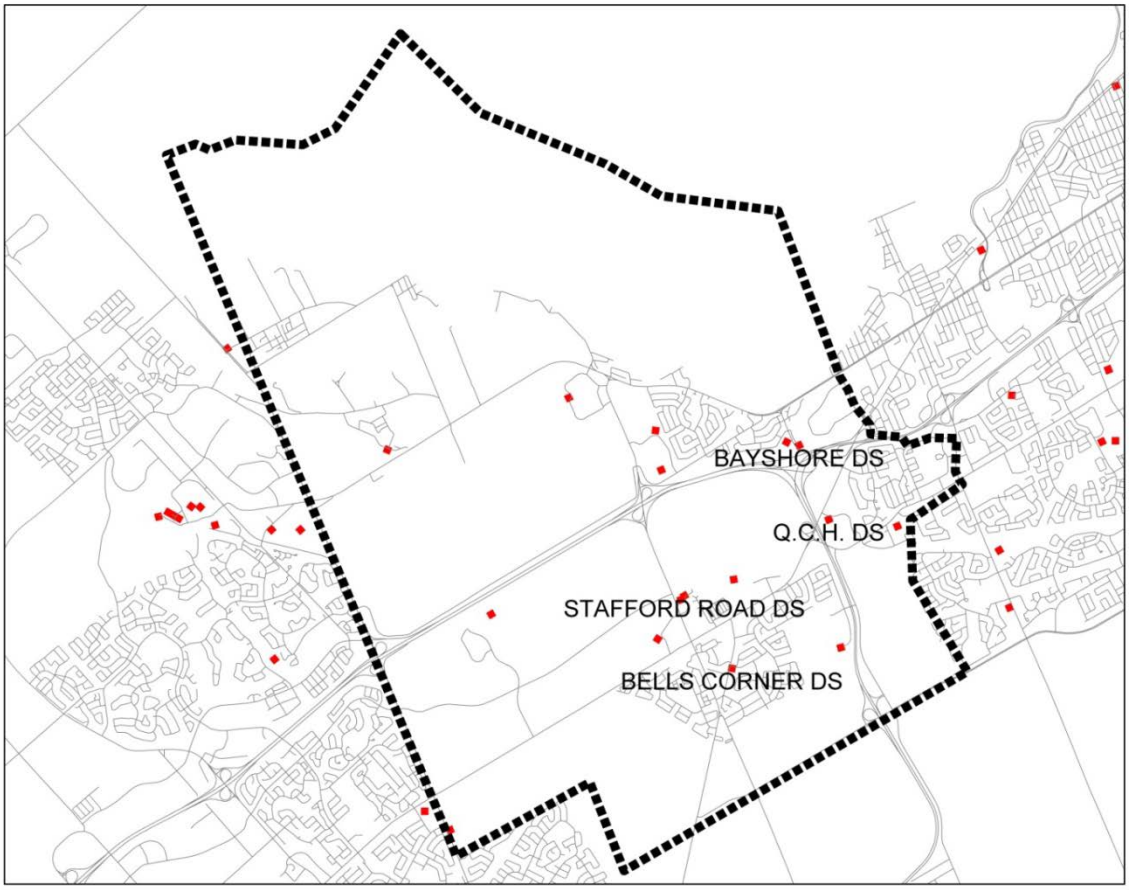
(a) Borden Farm DS – 8MVA (2015)
(b) Merivale MS – 12MVA (2017)
(c) New 27KV Feeders – 15MVA (2021)

1

West Nepean 8kV System

The West Nepean 8kV supply region includes the north-west portions of Nepean. This region is supplied by the Bayshore DS, QCH DS, Stafford Road DS and Bells Corners DS 8kV substations. Figure 3.1.20 shows the supply region of the West Nepean 8kV System.

Figure 3.1.20 - West Nepean 8kV Supply Region



Growth in the 8kV West Nepean supply region has been very slow in the last couple of years. This trend is expected to continue since no major projects for this area have been identified, except for the Bayshore Mall expansion which is expected to bring an additional demand of 2MVA in the next 1-2 years.

The existing 8kV West Nepean area is below the capacity limitations. No major issues have been identified in this area of Nepean; however, the transformers at these stations are approaching end of life and will need replacement during the duration of this study period.

Over the next 20 years, very little growth is expected for the west area of the Nepean region. The expected growth will not push the stations and feeders to their capacity limits.

Bayshore T1

The T1 transformer at this station will be reaching end of life by 2018. Currently, the transformers at this location do not match in size. It is recommended that the transformation at the station be upgraded to 15MVA. The planned capacity upgrade will improve the supply availability under a contingency scenario.

Bells Corners DS

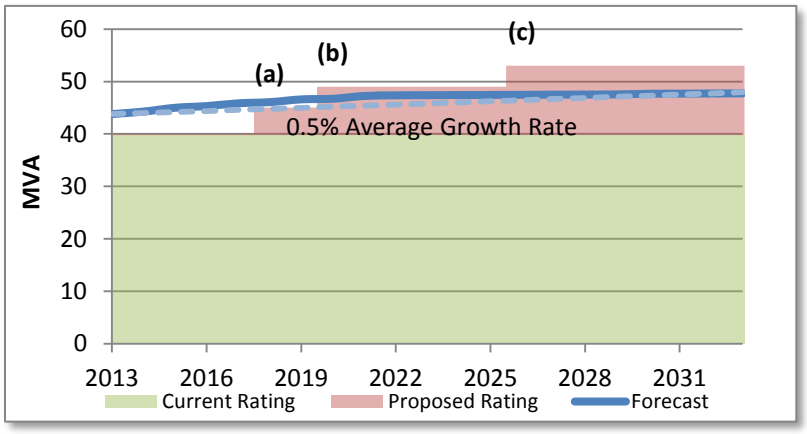
The transformers at this station will be reaching end of life by 2020. It is recommended that the transformation at the station be upgraded to 2 x 12MVA.

QCH DS

The transformers at this station will be reaching end of life by 2026. It is recommended that the transformation at the station be upgraded to 2 x 12MVA.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.21.

Figure 3.1.21 - West Nepean 8kV Load Growth



Capacity Projects

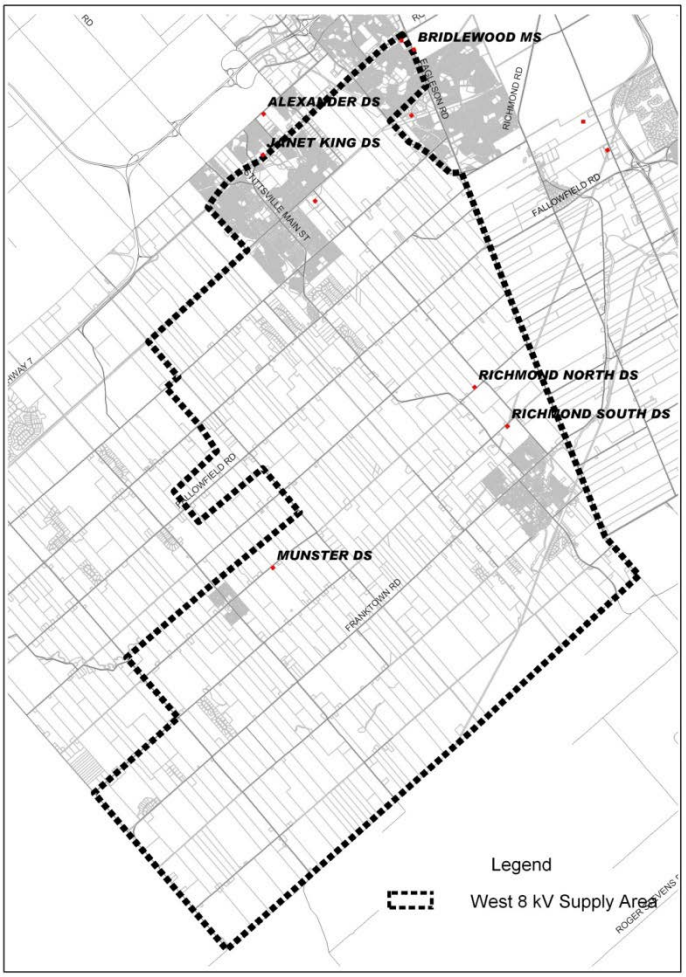
Planned:

(a) Bayshore T1 – 5MVA (2018)
(b) Bells Corners DS– 4MVA (2020)
(c) QCH DS – 4MVA (2026)

3.1.5.1.7 West 8kV System

The West 8kV supply region includes South Kanata, Stittsville, the Village of Richmond and Munster Hamlet. This region is supplied by the Bridlewood MS, Janet King DS, Munster DS, Richmond North DS and Richmond South DS 8kV substations as well as by the 28kV substations Alexander DS, Beckwith DS and Janet King DS through the use of distribution step-down transformers (28kV to 8kV). Figure 3.1.22 shows the supply region of the West 8kV System.

Figure 3.1.22 - West 8kV Supply Region



Growth in the west 8kV supply region is driven primarily by the growth in the Village of Richmond. Based on the Village of Richmond, City of Ottawa plans and available information from other agencies, the key developments which will continue to drive growth in this supply region are all centered in Richmond and detailed in the Village of Richmond Community Design

Plan (CDP). The Village of Richmond CDP outlines the expansion of industrial and commercial areas as well as an increase of 2,850 – 3,950 dwelling units.

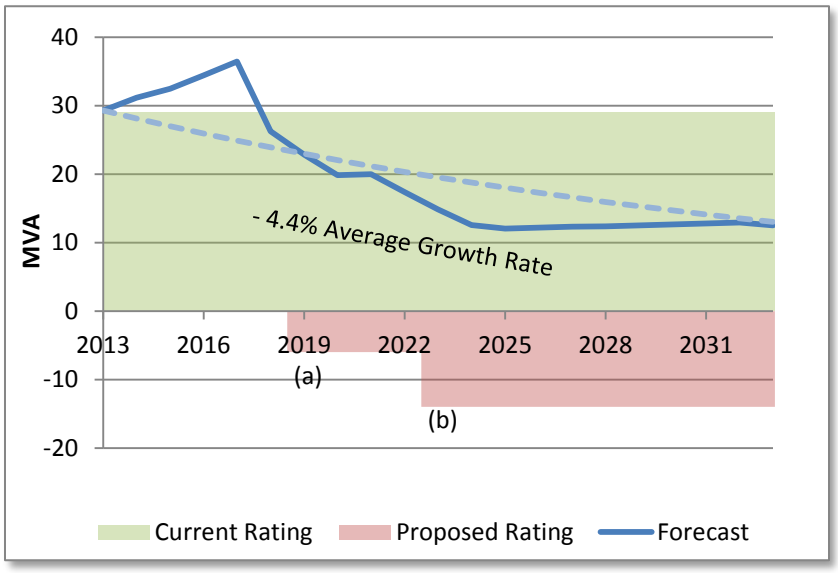
Overall, the existing west 8kV area is supplied by an adequate network of trunk feeders. There is however the need to expand the system to cover areas seeing growth. As there are very few 8kV feeders (9) that span a vast geographic region there are limits to capacity as well as the ability to restore under contingency.

Based on the load growth predicted in the Village of Richmond as well as capacity demand for Trans Canada's Energy East Pumping Station, there is a need in the short term to increase capacity with voltage conversion at Richmond South DS.

Due to aging infrastructure in the Glen Cairn community and at Bridlewood MS substation, reliability has been greatly impacted and has prompted a station rebuild. This project is planned to completely rebuild the substation by replacing the existing four transformers supplying both 8kV and 28kV, with two 75 MVA units supplying solely 28kV in 2019.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.23.

Figure 3.1.23 - West 8kV Load Growth



Capacity Projects

Planned Voltage Conversions:

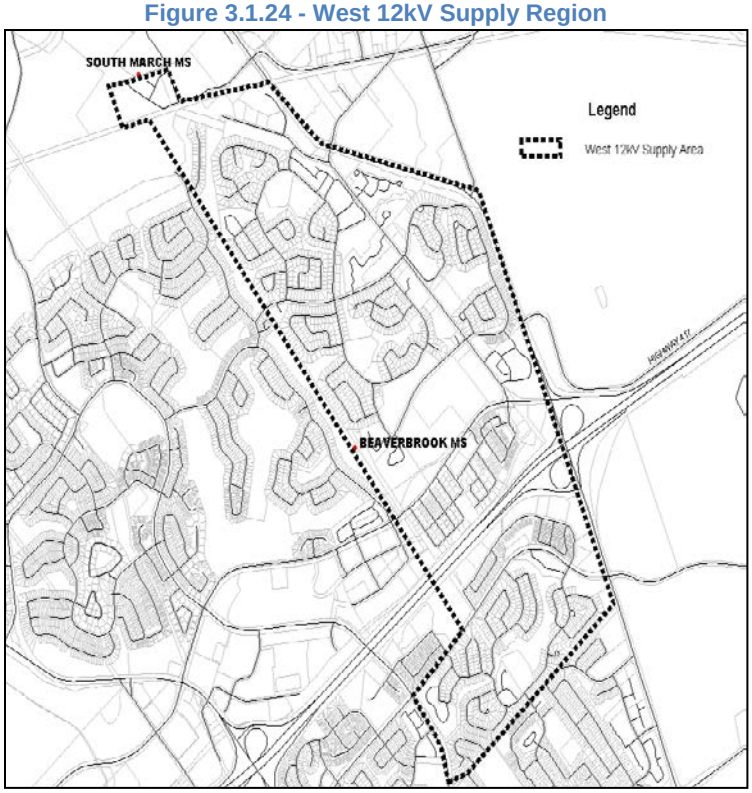
(a) Richmond South DS Reduction of 6 MVA (2016)

(b) Bridlewood MS

3.1.5.1.8 West 12kV System

The West 12kV supply region is located in central Kanata, including the communities of Katimavik and Beaverbrook. This region is supplied by the Beaverbrook MS, and South March MS substations. Figure 3.1.24 shows the supply region of the West 28kV System.

Figure 3.1.24 - West 12kV Supply Region



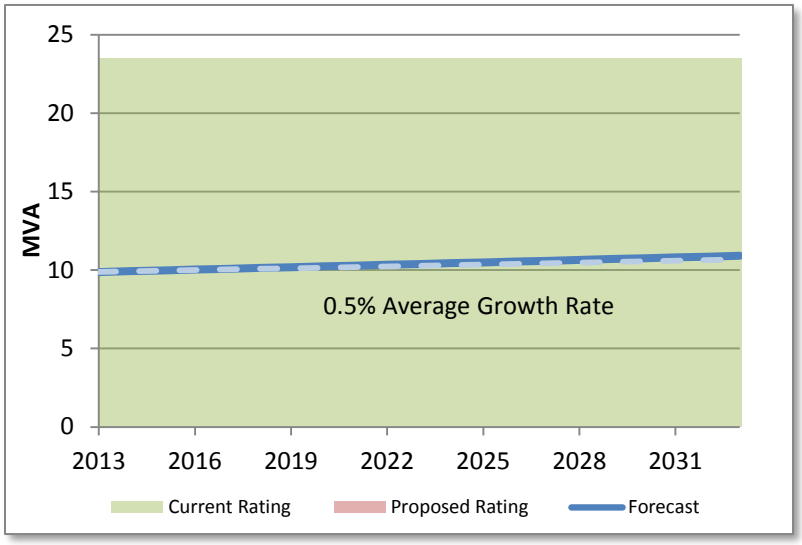
The West 12kV area is bounded by 28kV supplied areas on all sides and is anticipated that all future growth will be supplied from 28kV sources.

Overall, the existing West 12kV area is supplied by an adequate network of trunk feeders and can be recovered in N-1 contingency circumstances.

Based on only infill load growth predicted in the west 12kV supply area, the system will only require regular inspection and maintenance to continue providing the demanded capacity.

The forecasted 20 year load growth along with planned capacity upgrade projects is shown in Figure 3.1.25.

Figure 3.1.25 - West 12kV Load Growth



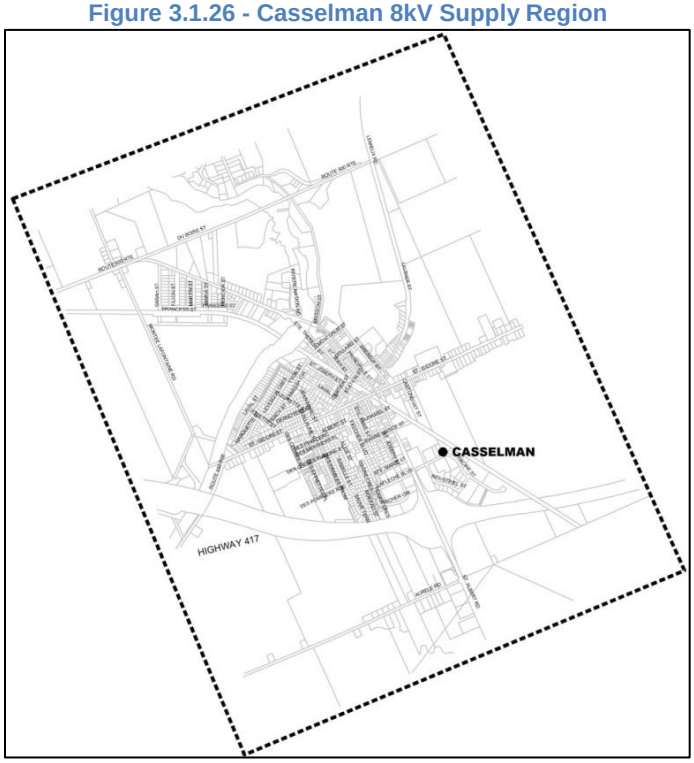
Capacity Projects

None

3.1.5.1.9 Casselman 8kV System

The Village of Casselman is supplied from a single station, Casselman MS at 8.32kV from three circuits. Figure 3.1.26 shows the Casselman supply area.

Figure 3.1.26 - Casselman 8kV Supply Region

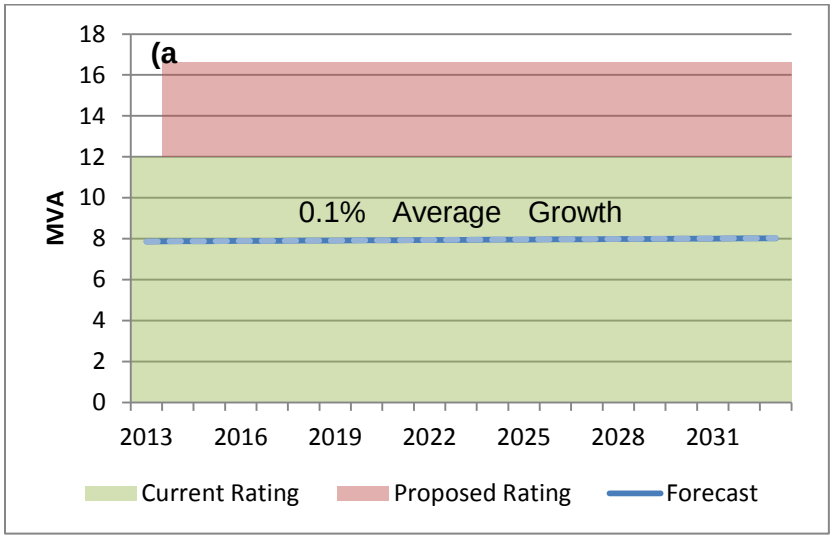


Overall, the Casselman area is supplied by an adequate network of trunk circuitry, however there is no redundancy at the station level since it is a single transformer with a single supply. In order to provide redundancy for contingency situations, a second transformer is planned to improve reliability to the area.

Growth within the Village of Casselman has been slow, and there are no major developments anticipated in the region over the next 20 year forecast period.

The forecasted 20 year load growth along with planned is shown in Figure 3.1.27.

Figure 3.1.27 - Casselman 8kV Load Growth



Capacity Projects

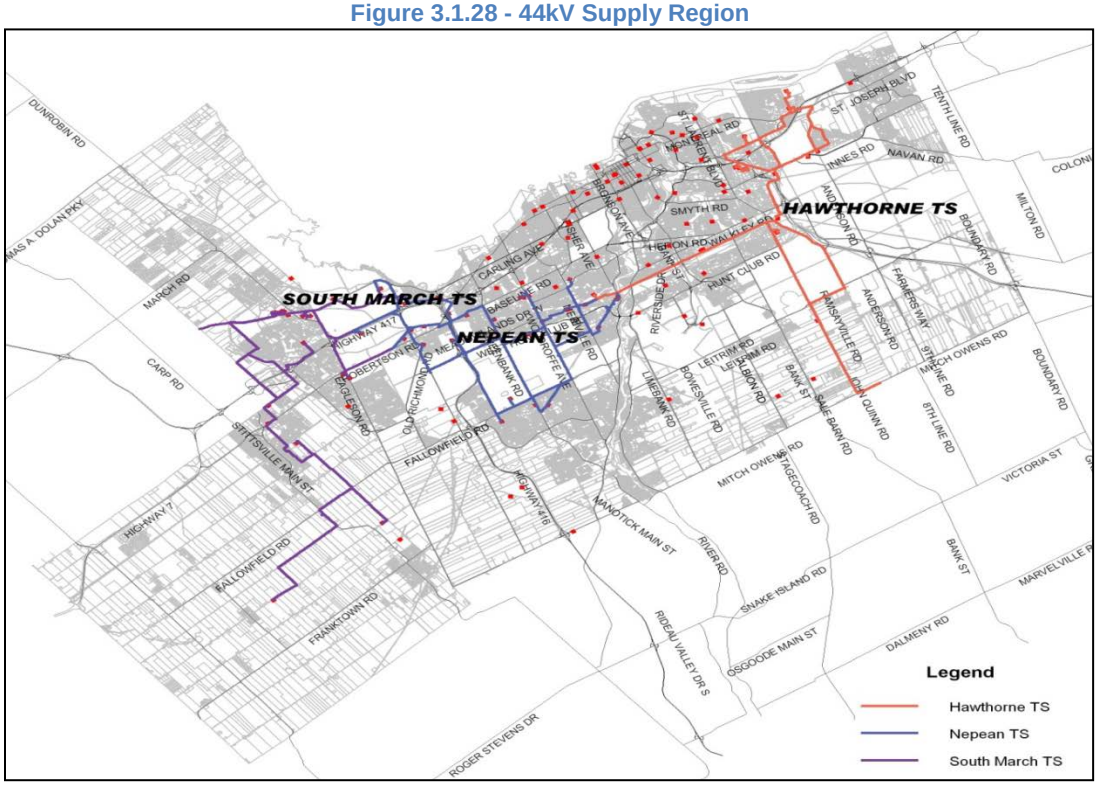
Planned:

(a) Casselman T2 – 5MVA (2014)

3.1.5.1.10 Citywide 44kV System

The 44kV system spans the entire service area and is supplied from three stations: Hawthorne TS, Nepean TS and South March TS. This system supplies a number of large industrial customers as well as 44kV to 28kV and 44kV to 8.32kV HOL substations. Figure 3.1.28 outlines the trunk circuit routing from each of these three stations.

Figure 3.1.28 - 44kV Supply Region



Each station area is essentially independent of the others with limited connections between South March TS and Nepean TS and between Hawthorne TS and Nepean TS.

Based on the vast area that these stations cover and their independent nature, they have been studied as separate stations as opposed to as a single region. Through the Regional Planning Study currently under way with the OPA (now IESO) and HONI, the load forecast for each of the stations has been developed.

In order to improve reliability performance in the East end of the City the loop of feeders from Hawthorne TS will be automated, the details of which can be found in the Reliability Plan Report as part of the 2014 Annual Planning Report, Attachment B-1(B).

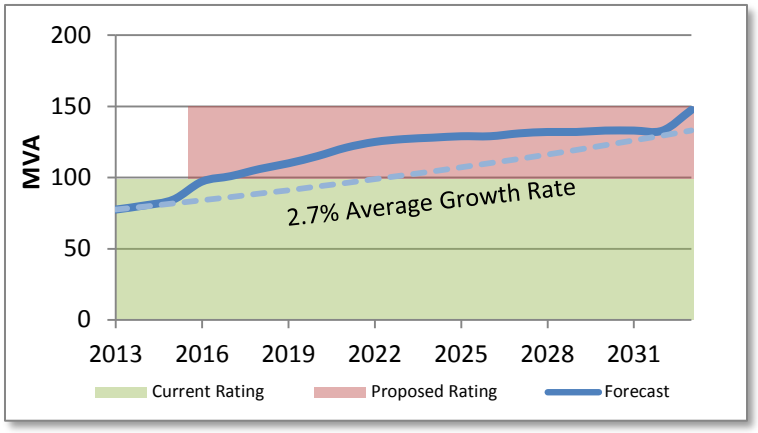
The Nepean TS 44kV system is built in a network configuration and at this time there are no significant issues identified with the distribution arrangement.

The 44kV trunk network from South March TS is adequate, except for the single radial feeder (A9M3) that runs south of Maple Grove Road. The radial section of A9M3 supplies three 44/8kV stations: Janet King DS, Richmond North DS and Munster DS. In order to improve reliability performance the 22M25 out of Nepean TS will be extended into the southern part of the West service territory to serve as a backup to these stations. Construction is anticipated and to begin in 2015 and be operational in 2017.

Additional capacity is required at Hawthorne TS in the near term and at South March TS in the long term, after the end of the study period. HONI is currently replacing the T7 and T8 230kv-44kV transformers with an expected LTR of 152MVA and in service date of 2017. An additional 44kV station is being proposed in the Richmond area which will create dual supplies to some of the rural 44kV supplied substations, create additional feeder ties for contingency operability and will help off-load the heavily loaded feeders from South March TS and Nepean TS.

The forecasted 20 year load growth along with planned capacity upgrade projects for each station are shown in Figure 3.1.29, Figure 3.1.30, and Figure 3.1.31.

Figure 3.1.29 - Hawthorne TS Load Growth

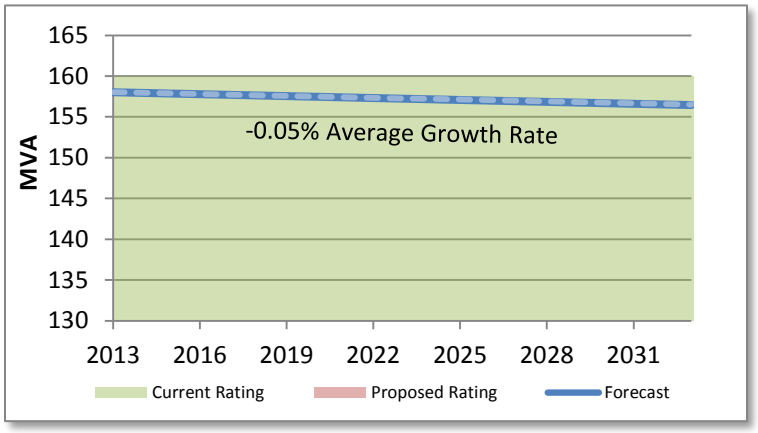


Capacity Projects

Planned:

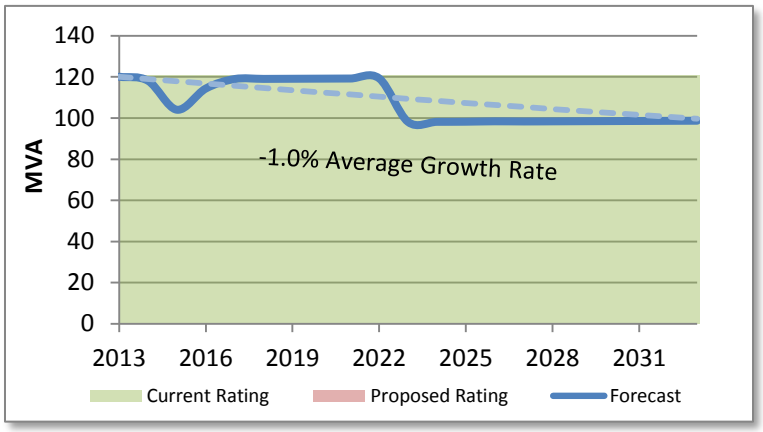
(a) Hawthorne TS – 51MVA (2017)

Figure 3.1.30 - Nepean TS Load Growth



There are no capacity issues forecasted at Nepean TS. The load forecast shows a decreasing trend based on the conversion of 8kV load (fed from 44/8kV stations) to the 28kV system.

Figure 3.1.31 - South March TS Load Growth



There are no capacity issues forecasted at South March TS during the study period. The load forecast shows a decreasing trend based on load transfers to transmission connected stations.

3.1.5.2 Ability to Connect New Generation

System ability to connect distributed generation is limited by several factors such as:

1. **Station Loading** – some station transformers have limited or no capability for reverse power flow. At these stations, total connected generation cannot exceed either 60% of top transformer rating plus minimum loading, or in the most restrictive case where there is no reverse flow capability, generation is limited to the minimum station loading. This limit has been adopted from HONI's evaluation tool for generation connection assessment.
2. **Feeder Thermal Rating** – the feeder ampacity rating must be respected to not overheat the conductors and connected equipment. For distributed generation, the available thermal capacity is the full feeder ampacity rating less contingency loading.
3. **Short Circuit Rating** – connection of distributed generation will increase the available current that flows through the system during faults. The total available current during faults cannot exceed the equipment ratings.
4. **Power Quality** – four concerns arise when connecting distributed generation:
    a. harmonics caused by inverter based generation;
    b. phase imbalance caused by single-phase generators;
    c. voltage instability caused by generators connected at various points along a feeder, or by induction generators requiring reactive power; and
    d. flicker caused by generators intermittently turning on and off – they can affect the voltage on the circuit impacting the quality of supply to HOL customers.
5. **Anti-Islanding** – distributed generation may introduce safety and power quality issues in the event of continued generation after loss of supply from the distribution system. The installation of transfer trips and other anti-islanding methods are used to limit islanding.

The generation connected to both feeders and station must be managed to prevent adverse impact to existing HOL load and generation customers.

As of July 30, 2014, HOL's Service Area was no longer under a transmission constraint due to the short circuit rating of 115kV transmission breakers located at the Hydro One Networks Inc. (HONI) owned Hawthorne TS. As a result, 300MW of generation capacity is now available.

Despite this, some stations remain restricted from any generation connection regardless of size and are discussed in the sections that follow.

Core 13kV

Currently, there are connection restrictions at the Slater TS, and one bus at Lisgar TS. Slater TS is limited due to short circuit levels at the station, whereas Lisgar TS is currently limited by the minimum normal loading on the station bus. Proposed upgrades at Lisgar TS substation will allow loading at this station to increase, which is anticipated to alleviate the current restriction at this location.

HOL has discussed with a few proponents their interest in large size district heating & cooling, hydro-generation, or energy storage within this region. With the coming load growth and planned station upgrades it is anticipated that capacity will be available to accommodate these requests.

East 13kV

There are currently no regional substation restrictions for the connection of distributed generation at the East 13kV substations; however; there are proposed upgrades at King Edward TK substation that may result in a constraint due to an increased fault current from the larger substation transformers.

West 13kV

Presently, the Lincoln Heights TS B1B2 bus pair is restricted to allow connection of only renewable micro-generation due to thermal limitations.

The OPA (now IESO) has approved a 29.35MW large hydro generation facility that will connect to Carling TS with an anticipated in service date of 2017.

As per the manufacturer's recommendation, HONI is presently restricting reverse flow through the existing Hinchey TH transformers to the minimum station load. The planned station upgrade will allow for more loading of Hinchey TS, and reverse flow of 60% of the top transformer rating plus minimum load with the requirement to keep the loading (with and without generation) on the secondary windings balanced.

South 28kV

Currently, the T1 half of Fallowfield MTS is restricted due to thermal limitations as well as a zero reverse flow capability. The T2 side of the station was built with reverse flow capability allowing the connection of generation dependant on remaining capacity available as applications currently exist for large generation to make partial use of this capacity.

South-East 28kV

There are currently no station restrictions for the connection of distributed generation at the South-East 28kV stations.

East 8kV & 28kV

There are currently no station restrictions for the connection of distributed generation at the East 28kV & 8kV stations.

West 28kV

There are currently no station restrictions for the connection of distributed generation at the West 28kV stations. HOL is attending to a proponent with a 4MW IESO energy storage offer-of-contract for transmission grid support. This project will connect to the Terry Fox MTS.

Nepean Core 8kV

There are currently no station restrictions for the connection of distributed generation at the Nepean Core 8kV stations.

West Nepean 8kV

There are currently no station restrictions for the connection of distributed generation at the West Nepean 8kV stations. All these stations are supplied from HONI High Voltage Distribution Stations (HVDSs), either South March TS or Nepean TS.

West 8kV

There are currently no station restrictions for the connection of distributed generation at the West 8kV stations.

West 12kV

There are currently no station restrictions for the connection of distributed generation at the West 12kV stations.

City Wide 44kV

There are currently no station restrictions for the connection of distributed generation at the 44kV Stations.

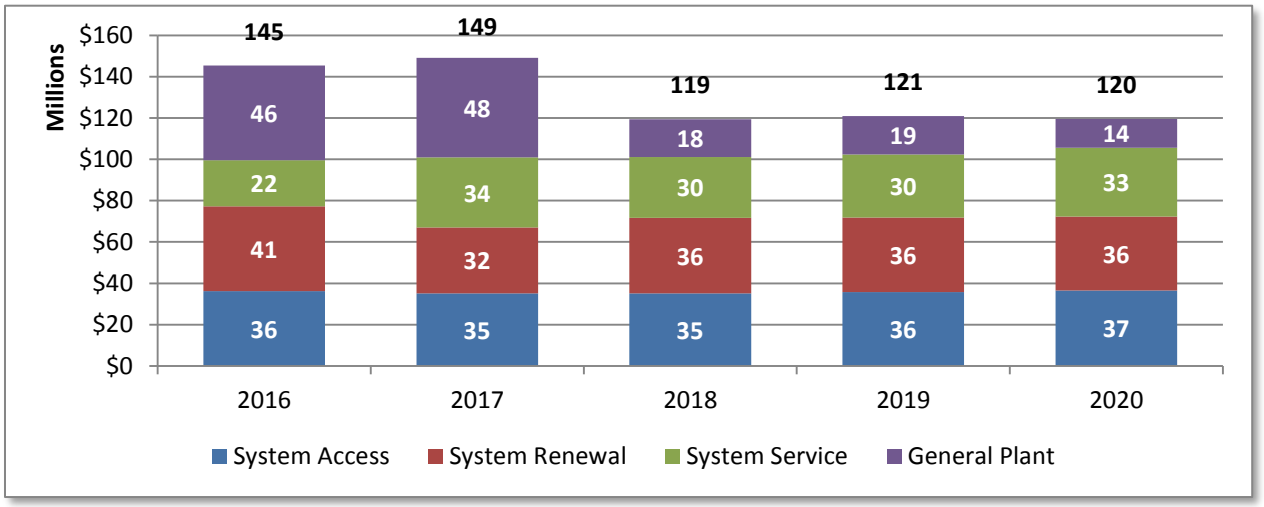
3.1.6 Total Annual Capital Expenditures by Category

HOL's total annual capital forecasted expenditure by investment category is shown in Table 3.1.6 and Figure 3.1.32.

Table 3.1.6 - Total Annual Capital Forecasted Expenditures by Investment Category

Investment Category	$'000				
	2016	2017	2018	2019	2020
System Access (Gross)	36,263	35,156	35,132	35,835	36,551
System Renewal	41,033	31,823	36,491	35,980	35,718
System Service	22,235	33,957	29,518	30,473	33,314
General Plant	45,899	48,138	18,276	18,695	13,954
Grand Total	**145,430**	**149,073**	**119,418**	**120,982**	**119,538**

Figure 3.1.32 - Total Annual Capital Forecasted Expenditures by Investment Category



3.1.7 Capital Expenditures Description by Category

HOL's capital expenditures are driven by the Asset Management planning process which is described in section 2.1 Asset Management Process Overview. The following sections describe, by investment category, how the outputs of the planning process tie into the allocation of the capital budgets.

3.1.7.1 System Access

System Access capital expenditures are driven by HOL's mandate to connect customers to the distribution system and to meet the service obligations of the Distribution System Code. The System Access Budget Programs are: Plant Relocation & Upgrade, Residential Subdivisions, Commercial Development, System Expansion, Embedded Generation, Infill Service (Res & Small Com), and Damage to Plant (see section 3.1.1 for a brief definition of the Budget Programs). System Expansion Demand contributions are determined though the application of the Board's prescribed economic evaluation methodology.

The capital planning process has minimal impact on System Access Capital Expenditures since these expenditures are demand/customer driven and are therefore typically considered to be mandatory.

Forecasted annual spending takes into consideration a number of variables:

- Historic spending levels – trending of each category;
- Known large future developments;
- City plans and projects; and
- Economic indicators

Where efficiencies are identified in combining activities, system renewal or system service projects are considered to allow all work in one area to take place together. System access projects may in some cases require a system renewal or service project to be delayed due to physical restrictions in the work area or system operability restrictions. In these circumstances, the risk to the system is evaluated and an optimal solution is determined with regards to work timing and prioritization.

3.1.7.2 System Renewal

System Renewal investments include sustainment programs that replace or refurbish assets which are nearing or have reached the end of their useful lives. The System Renewal Budget Programs are: Stations Transformer Replacement, Stations Switchgear Replacement, Stations Plant Failure, Stations Enhancements, Pole Replacement, Insulator Replacement, Elbow & Insert Replacement, Distribution Transformer Replacement, Vault Rehab or Removal, Civil Rehabilitation, Cable Replacement, Switchgear New & Rehab, O/H Equipment New & Rehab, and Distribution Plant Failure (see section 3.1.2 for a description of the Budget Programs).

Capital expenditures for System Renewal are sustainment investments that are determined as an output of the Asset Investment Strategy (Section 2.1 Asset Management Process Overview) and are captured annually in the Annual Planning Report (Attachment B-1(B)). The primary planning pieces which impact System Renewal investments are the Asset Management Plan and the Testing, Inspection & Maintenance Plan. The Asset Management Plan provides strategic guidance on replacement and investment forecasts, manages priorities, and identifies process gaps. The Testing, Inspection, and Maintenance Plan outputs data used in the development of asset condition assessment and aims to optimize maintenance practices and therefore, overall asset lifecycle.

Full details on how System Renewal Investments are determined and prioritized can be found in section 2.1 Asset Management Process Overview.

3.1.7.3 System Service

System Service investments include sustainment programs that address capacity, reliability, and power quality issues on the distribution system. The System Service Budget Programs are: Stations New Capacity, Line Extensions, System Reliability, Distribution Enhancements, Distribution Automation, Substation Automation, SCADA Upgrades, and RTU Additions (see section 3.1.3 for a description of the Budget Programs).

Capital expenditures for System Service are investments that are determined as an output of the Asset Investment Strategy (Section 2.1 Asset Management Process Overview) and are captured annually in the Annual Planning Report (Attachment B-1(B)).The primary planning pieces which impact System Renewal are the System Capacity Plan and the Reliability Plan.

The System Capacity Plan identifies milestones for required system upgrades to ensure a reliable supply is maintained. The Reliability Plan provides a platform for thorough review of system reliability and identifies planned works which are designed to directly impact system reliability.

3.1.7.4 General Plant

General Plant investments include payments to Hydro One under Connection & Cost Recovery Agreements, facility and fleet requirements, Information Technology system upgrades, and new initiatives. The General Plant Budget Programs are: Facilities Management, Fleet Replacement, Tools Replacement, IT Life Cycle and On-going Enhancements, IT New Initiatives, ERP System, Customer Service, and Operation Initiatives.

Forecasted annual spending takes into consideration a number of variables:

- Identification of lifecycle optimization, examples including building facilities, vehicles, and tools. The objective is to determine the optimal replacement to minimize overall costs but also maintain a safe work environment;
- Identification of any IT system upgrades required to continue with vendor support and maintain data integrity;
- All new Operation initiatives must align to business plan priorities, help achieve approved performance targets, and support the four key areas of focus (Customer Value, Financial Strength, Organizational Effectiveness, and Corporate Citizenship). Funding must be justified and supported by business case and approved by Executive Management Team (EMT).

3.1.8 Forecasted Material Capital Expenditures

The following section outlines the material capital expenditures, by category, planned over the forecast period, which exceed the materiality threshold of $750k.

3.1.8.1 Committed Investment

Annual budgets for 2015 and 2016 have been prepared and identify projects by Investment Category, Capital Program and Budget Program. Table 3.1.7 and Table 3.1.8 list the projects executing in 2015 and 2016 that exceed the materiality threshold. It should be noted that this

number represents the total project cost and therefore may incorporate project expenditures which fall outside of the 2015-2020 window (either before or after). The full justifications of these projects can be found in Attachment B-1(A).

Table 3.1.7 - Material Capital Expenditures for 2015 and 2016 Projects (1/2)

Investment Category	Capital Program	Budget Program	Project	Total Budget $'000
System Renewal	Station Assets	Station Trans. Replace.	Merivale DS Rebuild	17,126
			Bronson T1 & T2 Replacement	3,223
			Longfields T2	4,340
			Albion UA T1, T2 & T3 Replacement	2,970
		Station Switchgear Replacement	Epworth T1 Primary Fuse to Circuit Switcher	1,149
			Woodroffe TW 13kV Switchgear Replacement	7,346
			Borden Farms Switchgear Replacement	7,269
			Bayshore Primary Circuit Switcher	3,782
			Overbrook TO Switchgear Replacement	7,130
			Startop Protection Upgrade	4,768
	Distribution Assets	Pole Replacement	Centretown East Pole Replacement	7,416
			South East Kilborn Area Pole Replacement	1,054
			Riverside South Pole Replacement	4,565
			Grandview Road Pole Replacement	1,086
			Centretown West Pole Replacement	6,681
			Alphabet Ave Pole Replacement	1,224
			Prince of Wales & Greenbank	2,456
		Dist Trans Replace	OH TXF – PCB Regulatory Compliance	1,473
		Civil Rehab.	Civil on Carling from Bronson to Sherwood	2,602
		Cable Replacement	48M4 & 48M5 Cable Replacement	841
			Butyl Rubber Craig Henry	1,604
			Stittsville Main Cable Replacement	2,868
			Blackburn 4F8	1,611
			Butyl Rubber Tanglewood	2,540

Investment Category	Capital Program	Budget Program	Project	Total Budget $'000
		O/H Equipment New & Rehab	SMD-20 Switch Replacement	1,250
		Metering	Remote Disconnect Smart Meters	6,800

1 **Table 3.1.8 - Material Capital Expenditures for 2015 and 2016 Projects (3/2)**

Investment Category	Capital Program	Budget Program	Project	Total Budget $'000
System Service	Stations Capacity	Stations New Capacity	New South 28kV Substation	21,255
			Hinchey New Switchgear Lineup	11,280
			Lisgar TL Transformer Upgrade	TBD*
			Limebank Transformer Upgrade	8,360
			Leitrim T1	3,050
			Casselman T1	4,740
			Richmond South DS	17,657
	Distribution Enhancements	Line Extension	TM1AH Capacity Upgrade	880
			Alta Vista Tie	1,658
			Orleans TS Feeder	4,546
			Fernbank Rd Line Extension	1,533
			West 44kV Line Extension	6,243
			Springbrook Drive Trunk Extension	2,363
			Abbott Street Trunk	1,023
		System Voltage Conversion	Woodroffe UW Voltage Conversion	15,835
			Prince of Wales Voltage Conversion	1,475
			Rideau Valley Voltage Conversion	1,035
			Richmond Voltage Conversion	8,320
			Goulbourn St Voltage Conversion	802
	Auto-mation	Dist. Auto.	Telecommunications Master Plan	17,000
		SCADA Upgrade	SCADA Replacement	2,800

2 *Note – the budget for Lisgar TL Transformation Upgrade is currently being prepared by Hydro
3 One.

3.1.8.2 2017-2020 Investments

For the 2017-2020 forecasted years, total Budget Program level spending has been projected, as shown in Table 3.1.9, Table 3.1.10, Table 3.1.11, and Table 3.1.12. Note that all programs are shown including those that do not exceed the materiality threshold of $750k. Project specific investments will be identified on an on-going basis, always looking out three years at a time. Project and Budget Program Justifications can be found in Attachment B-1(A).

1

Table 3.1.9 - Forecasted Capital Expenditures by Budget Program – System Access

Investment Category	Capital Program	Budget Program	$'000			
			2017	2018	2019	2020
System Access	Plant Relocation	Plant Relocation & Upgrade	7,773	7,928	8,087	8,248
	Residential	Residential Subdivision	7,027	7,167	7,311	7,457
	Commercial	New Commercial Dev	13,042	12,576	12,827	13,084
	System Expansion	System Expansion Demand	2,366	2,413	2,462	2,511
	Stations Embedded Gen	Embedded Generation	384	392	400	408
	Infill & Upgrade	Infill Service (Res & Small Com)	3,223	3,288	3,353	3,420
	Damage To Plant	Damage to Plant	1,171	1,195	1,219	1,243
	Metering	Metering – Re-verification	-	-	-	-
		Smart Meters	-	-	-	-
		Suite Metering	170	173	177	180
	Total		35,156	35,132	35,835	36,551

2

Table 3.1.10 - Forecasted Capital Expenditures by Budget Program – System Service

Investment Category	Capital Program	Budget Program	$'000			
			2017	2018	2019	2020
System Service	Stations Capacity	Stations New Capacity	15,272	10,464	14,441	15,626
	Distribution Enhancements	Line Extensions	6,180	7,132	6,455	6,739
		System Voltage Conversion	4,964	5,729	5,185	5,413
		System Reliability	445	513	464	485
		Dist. Enhancements	694	801	725	757
	Automation	SCADA Upgrades	1,011	556	51	51
		SCADA - RTU Additions	76	87	79	82
		Distribution Automation	4,719	3,548	2,449	3,510
		Stations Automation	597	689	624	651
	Total		33,957	29,518	30,473	33,314

Table 3.1.11 - Forecasted Capital Expenditures by Budget Program – System Renewal

Investment Category	Capital Program	Budget Program	$'000			
			2017	2018	2019	2020
System Renewal	Stations Asset	Stations Transformer Replacement	4,620	6,533	8,225	7,965
		Stations Switchgear Replacement	7,088	7,408	6,871	6,114
		Stations Plant Failure	107	107	107	107
	Stations Refurbishment	Stations Enhancements	634	731	662	691
	Distribution Asset	Pole Replacement	6,592	7,608	6,886	7,189
		Insulator Replacement	168	194	176	183
		Elbow & Insert Replacement	190	219	198	207
		Dist. Transformer Replacement	808	933	844	881
		Civil Rehabilitation	636	734	664	694
		Cable Replacement	5,262	6,073	5,496	5,738
		Switchgear New & Rehab	376	434	393	410
		O/H Equipment New & Rehab	902	1,041	942	983
		Plant Failure Capital	2,893	2,893	2,893	2,893
	Metering	Remote Disconnected Smart Meter	1,547	1,584	1,623	1,662
	Total		31,823	36,491	35,980	35,718

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Table 3.1.12 - Forecasted Capital Expenditures by Budget Program – General Plant

Investment Category	Capital Program	Budget Program	$'000			
			2017	2018	2019	2020
General Plant	Buildings – Facilities	Buildings – Facilities	509	408	323	243
	Customer Service	Customer Service	2,361	1,148	6,658	1,139
	ERP System	ERP System	354	350	354	1,061
	Fleet Replacement	Fleet Replacement	1,209	1,452	1,480	1,876
	Info Serv & Tech New Initiatives	Info Serv & Tech New Initiatives	1,166	1,006	1,218	1,203
	IT Life Cycle & Ongoing Enhancement	IT Life Cycle & Ongoing Enhancement	1,737	1,905	2,232	1,816
	Operation Initiatives	Operation Initiatives	452	405	892	1,069
	Tools Replacement	Tools Replacement	521	530	539	548
	Hydro One Payments	Hydro One Payments	5,000	5,000	5,000	5,000
	Facilities Implementation Plan	Facilities Implementation Plan	34,829	6,073	-	-
	Total		48,138	18,276	18,695	13,954

3.1.9 Regional Planning Process

HOL is currently participating in the Integrated Regional Resource Planning process (IRRP) with Hydro One Network Inc., Hydro One Distribution, and the Independent Electricity System Operator (IESO) as described in 1.2.1.1 Integrated Regional Resource Planning Process. The IRRP began in 2011 and continues to be developed by the working group, with the IESO leading the process. The IESO has issued a hand off letter to Hydro One Networks Inc. initiating development work on near and mid-term transmission solutions to meet the identified needs. As per the hand off letter, found in Appendix B, two transmission solutions have been identified that impact HOL's capital expenditure plan: rebuilding of the existing 115 kV single-circuit A6R and upgrading a section of 115 kV S7M. It has been determined that to increase the available capacity of the Hydro One circuit S7M HOL overhead line that passes beneath it must be lowered by 2.5 feet through the crossing. The costs associated with the work is budgeted at approximately $10k and is scheduled for completion in 2015.The plan for the Hydro One circuit A6R upgrade will be developed and implemented by Hydro One Networks Inc. Currently, the date and cost is not known, no estimate has been provided, and there is potential that the costs of this work will fall within HOL's forecast years. As the timeline and costs of this work are beyond the control of HOL, any work will be integrated into the current plan through reprioritization of work following the planning process. HOL will continue to provide updates as more information becomes available.

3.1.10 Customer Engagement Activities

As an overview, this section outlines the activities HOL undertakes to solicit feedback from customers. Some examples of outcomes are provided in section 3.2.4 Customer Engagement

Each year, HOL engages an external research firm to conduct an annual Customer Satisfaction Survey. The survey helps HOL understand the satisfaction levels of HOL customers relative to Ontario comparators. It also reveals how customer perceptions, issues and concerns are evolving over time. The types of questions posed to customers in this annual survey include:

- LDC Knowledge, integrity, involvement and trust;
- Overall Customer Satisfaction scores;
- % of respondents indicating they had a blackout or outage issue in the past 12 months;

- % of respondents indicating they had a Billing problem in the past 12 months;
- What customers think of electricity costs;
- Level of customer engagement;
- Company Image; and
- Customer view of importance to pursue implementation of "SMART Grid"

The survey results factor into the setting of annual performance objectives and the establishment of relative priorities.

In addition to the annual survey described above, HOL also conducts monthly telephone surveys of customers who have recently called HOL's call center. This survey measures factors such as:

- Call Center level of Satisfaction;
- Level of knowledge of the staff who dealt with the customer;
- Level of courtesy of the staff who dealt with the customer; and
- The ability to deal with the customer's issue (First Call Resolution)

Use of these two surveys helps to determine if HOL is improving performance, from the customer's perspective, year over year. Further, these surveys help identify emerging issues which influence planning and resolution priorities. Annual plans are more informed and aligned as a result of customer feedback generated from these two surveys.

3.1.11 System Development Expectations

This section describes how HOL anticipates the system to develop over the next five years, including in relation to load and customer growth, smart grid development and the accommodation of forecasted renewable energy generation projects.

3.1.11.1 Load and Customer Growth

HOL's system capacity is lagging behind the load growth – currently 15% of substations are above their specified planning rating (see2.2.4 Capacity of the Existing System Assets). Over the next five years, HOL is expecting growth to continue as previous rural areas are changed to urban areas and the City's plan for intensification continues.

Overall, the City of Ottawa is seeing continued growth, primarily focused in four regions: the downtown core, Nepean & Riverside South, South Kanata & Stittsville and Orleans. This growth is being seen through the development of new mixed retail/residential communities as well as intensification of existing communities and the Light Rail Transit developments. Moving forward, significant investment in capacity for the system, at both the station and distribution level, will be required to catch up to and maintain pace with the demand. In addition, there are a number of distribution expansions which will be required to bring power from the substations to the customer site. These capacity upgrade projects are identified through the Capacity Planning process and the needs are described in Section 3.1.5.1 Ability to Connect New Load.

There are several upgrades of transmission interties within the City which may be necessary over the next 20 years to maintain adequate and reliable supply from the bulk system. HOL is currently involved in an IRRP (section 1.2.1.1 Integrated Regional Resource Planning Process) that is evaluating the transmission capacity and infrastructure requirements in the Ottawa region. The final report is expected by Q1 2015. Preliminary findings indicate required upgrades to address the following needs:

- Post-contingency thermal overload of the 115 kV double circuits in Downtown Ottawa M4G and M5G ;
- Additional station capacity needed in Downtown Ottawa area;
- Additional supply capacity needed in the south of Nepean area to support the growth;
- Post-contignecy thermal overload of one Merivale autotransformer; and
- The need for bulk transfer capability between Hawthorne and Merivale.

3.1.11.2 Smart Grid Development

HOL's Smart Grid Development is detailed in the Grid Transformation Action Plan (GTAP) report, found in Attachment B-1(C).

The term "Smart Grid" means different things to different people depending on their perspective and knowledge of the power system. One statement that captures the essence of Smart Grid is the following:

"The integration and application of real-time monitoring, advanced sensing, communications, analytics, and control, enabling the dynamic flow of both energy and information to

accommodate existing and new forms of supply, delivery, and use in a secure, reliable and efficient electric power system, from generation source to end-user."

In addition to the challenge of distributed generation, consumers are very aware of the increasing cost of electricity and are demanding greater control over their usage. At the same time they expect a high level of electricity supply reliability.

Governments are also keenly aware that demand control can play a significant role towards reducing overall cost in delivering electricity service in the future. The Grid Transformation Action Plan report is the first step in preparing HOL for the future Smart Grid.

Refusing to make progress in developing a smarter grid is not an option. At the same time HOL must not be reckless in the transformation plans. Being on the bleeding edge of technology is not something that many of our customers would value for HOL. A middle of the road approach of making prudent investments in proven technology will enable us to bring greatest returns to our customers.

HOL has identified a number of fundamental building blocks for the Smart Grid that requires study to ensure they will meet our future needs. Communication Infrastructure, data capture, storage and sharing, IT systems and cyber security are some of the fundamentals that are required to ensure a solid foundation for future projects.

HOL treats "Smart Grid" development activities within the regular processes to identify capital expenditures. It is anticipated that more focus will be placed on automation, including a robust communication infrastructure, in the coming years to allow for more efficient system operability and transparency.

3.1.11.3 Accommodation of forecasted renewable energy generation projects

HOL is predicting a continued interest in the installation of REG within the service territory, over the five year forecast period. Based on the current ability of the system to connect new REG (Section 3.1.5.2), there are no constraints at the anticipated connecting stations for the forecasted connections. For more detailed information on accommodation of forecasted

renewable energy projects in the next five years, please refer to 3.3 System Capability Assessment for Renewable Energy Generation.

3.1.12 Impact of Customer Preferences, Technology, and Innovation on Total Capital Cost

HOL uses the information gathered from customer engagement activities (section 3.2.4) to help meet customer preferences through the use of technology and innovation. The use of smart switches and enhanced communication systems to improve restoration times are two examples of the use of technology.

3.1.12.1 Response to customer preferences

See section 3.2.4 Customer Engagement.

3.1.12.2 Technology Based Opportunities

Over the next five years, HOL will continue implementing grid technologies to improve the reliability and efficiency of the distribution system. Ongoing targeted installation of automated devices is planned. Currently, targeted projects are the East 44kV automation, which will deploy automatic restoration to this sub-transmission loop that supplies 3% of HOLs' customers. In addition, automation plans are being deployed in the quickly growing South Nepean/Barrhaven area, as well as targeted annual installation to address the Worst Performing Feeders (1.3.2.1.3 Worst Feeder Analysis). Continued investment in the communication infrastructure will be essential to support current automation plans while maintaining the flexibility to integrate the technologies of tomorrow.

Starting in 2015, with a completion of installation in 2018, HOL's Supervisory Control and Data Acquisition (SCADA) is being upgraded. SCADA supports system reliability by providing system operators with real-time access to system status and control, reducing time required to identify service disruptions, locate system faults, and operate the system to restore customers. As more and more distribution assets are connected to the SCADA system, the Operator's situational awareness improves, resulting in a more focused and effective restoration effort.

In early 2014, HOL initiated a pilot project to deploy a small WiMAX network using the 1800 – 1830MHz band that has been reserved by Industry Canada for use in the management of the

electricity system. It is the goal of this project to evaluate the technology for use in distribution automation as well as SCADA and metering applications. While the WiMAX network will not provide the throughput of 3G/LTE systems, it does provide lower latency and a cost structure that will be more compatible with a utility budgetary framework.

HOL continues to evaluate the best mix of technologies to support increased communications across both distribution and substation equipment. Over the course of 2014, HOL engaged a leading utility communications consulting firm to develop a telecommunications master plan. This plan (completed in August of 2014) provides a complete picture of the core Wide Area Network which will accommodate all HOL communications needs. With this plan completed, a detailed investment roadmap has been crafted which describes the necessary investments and outcomes over the next 10 years. These investments will bring the HOL communications infrastructure from a disparate patchwork of costly services to a single cost efficient, secure, reliable, and effective communications network. By building a private communications infrastructure, HOL will reduce the ongoing burden of third-party service charges while at the same time providing connectivity and capacity exactly where it is needed.

3.1.12.3 Innovative Processes, Services, Business Models, or Technologies

In 2014, HOL acquired Copperleaf C55, an industry-leading and established Asset Investment Planning tool. This planning tool will enable the development of a strategic framework, improved asset analytics, investment decision optimization, and performance management. Copperleaf C55 will achieve the objectives of value creation through better decision making, improved efficiency in the planning process, and meeting the standards set by the OEB's performance-based Renewed Regulatory Framework. Implementation of Copperleaf C55 was completed in December 2014.

3.2 Capital Expenditure Planning Process Overview

The Capital Expenditure Planning Process Overview section outlines HOL's planning objectives, how non-distribution alternatives for relieving capacity and operational constraints are evaluated, a description of how HOL identifies, selects, prioritizes and paces investments, and the mechanisms used to engage customers.

3.2.1 Capital Expenditure Planning Objectives

HOL's capital expenditure Planning Objectives are as follows:

- To align with HOL's Corporate Strategic Objectives as outlined in Section 1.0.1: Customer Value, Financial Strength, Organizational Effectiveness, and Corporate Citizenship;
- To optimize projects by ranking investment criteria and comparing project benefits;
- To ensure that investments are financially viable in terms of the approved budget and required resources;
- To provide high quality customer service by evaluating customer value and striving to increase reliability;
- To maximize cost efficiency by considering timing, resource allocation and contingency scenarios;
- To analyze previous investments to improve future investment decisions; and
- To pace expenditures to minimize rate impact.

These objectives align with HOL's Asset Management Objectives in that the Planning Objectives define the selection and prioritization process for project investments. The Asset Management Objectives are: Health & Safety, Asset Management, Reliability & Customer Impact, Environment and Regulatory Compliance. They are detailed in section 2.1.1 Asset Management Objectives. Whereas HOL's Asset Management Objectives provide a focus on identifying the asset needs and enhancing the distribution system, the capital planning objectives aim to maximize the outcome of the invested capital, based on the available budget.

Both the Planning Objectives and the Asset Management Objectives revolve around HOL's primary area of focus: delivering customer value. As a company that provides an essential

service to the public, the ability to deliver value to its customers is critical to HOL's. The fundamentals of customer value in the electricity business are quality and cost — delivering a reliable service, while operating efficiently and effectively to minimize rate impact. HOL is consistently among the top performers in Ontario in both these areas, but the customer's place within the electricity system is also evolving. Customers are no longer just consumers of electricity, but also generators of electricity and managers of energy conservation, thereby making them integral and active participants in the management of the electricity system.

In order to meet and exceed the diverse expectations of the customer base, HOL is focussing on service quality and responsiveness, assisting customers in managing their energy consumption and electricity costs, and maintaining/improving overall system reliability.

HOL's approach includes:

- A focus on detailed customer knowledge to guide the company in understanding, anticipating and responding to customer needs;
- The revision of the conditions of service —operating practices, levels of service and connection policies — to be more customer-centric; and
- The effective and innovative use of technology and communication to enhance the customer experience, and provide solutions to help customers conserve energy and manage costs.

HOL also focuses on accommodating and implementing proposals for customer distribution generation projects. This includes solar generation projects under the Feed-In-Tariff (FIT) or microFIT programs. HOL works with the customer in the preparation of their connection proposal, ensuring that the equipment and design meets all required standards and regulations. A Connection Impact Assessment is completed by HOL as a formal response to the proposal, verifying that connection at the proposed location is viable and that the proposed generation will not negatively impact the grid.

3.2.2 Non-Distribution System Alternatives

HOL does not have a policy governing the treatment of non-distribution system alternatives to relieve capacity or operational constraints. HOL is currently involved in an Integrated Regional

Resource Planning process (IRRP) as developed by the IESO and updated by the OEB. The IRRP process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria (ORTAC), and develops regionally integrated solutions to address needs that are identified. These include: conservation, demand management, distributed generation, large-scale generation, transmission, and distribution. HOL continues to work with Hydro One, and the IESO in developing optimal solutions to the transmission and bulk system needs within the Ottawa area. Refer to section 1.2.1.1 Integrated Regional Resource Planning Process for more details.

3.2.3 Prioritization Process, Tools and Methods

HOL's process, tools, and methods used to identify and prioritize projects are described in 2.1.2 Asset Management Process Components.

The pace at which HOL plans project execution is dependent on three criteria:

- Customer service requests;
- Rate impact to customers; and
- System requirements – safety, reliability & capacity

Investments are scheduled and paced according to customer requirements and are coordinated to meet regulatory requirements based on crew availability.

The annual planning process as part of the Annual Planning Report (see Attachment B-1(B)), identifies a gap between the forecasted investment required for the distribution system, and the funding currently identified. That gap exists to some degree due to resource constraints including operational and capacity, and affordability constraints. The pattern of increased capital investment has placed pressure on rate impacts and financing capability. A balance must be found that ensures sufficient investment in the distribution system to enhance reliability and improve productivity and customer service, while achieving the deemed funding level through rates. Projects and new initiatives must be reviewed and prioritized to ensure the most essential investments with the greatest value to the customers are funded on a timely basis, within all the constraints.

3.2.4 Customer Engagement

HOL undertakes various customer engagement activities of which the following relate directly to the implementation of the Distribution System Plan.

Annual Customer Satisfaction Survey

Each year, HOL conducts a customer satisfaction survey which solicits customer feedback on the utility and the various services the utility provides. In 2014, 805 telephone interviews were conducted with a wide range of questions covering such topics as: system reliability performance, investment to improve reliability, acceptable length of outages, design of the system (overhead versus underground) and willingness to pay more for system enhancements.

Key results of the survey, including percentage of responses:

- Provides consistent, reliable electricity – 90%
- Not willing to pay for further improvements – 51%
- Willingness to pay at least something to better their electricity system – 43%
- Acceptable duration of an outage during extreme conditions:
    - None, the power should not go out – 7%
    - Less than 2 hours – 11%
    - 2 to 4 hours – 17%
    - 12 to 18 hours – 7%
    - 1 day – 10%
    - 1 to1.5 days – 5%
    - 1.6 to2 days – 5%
    - More than 2 days – 4%

Based on the survey results, HOL customers indicated that reliability be maintained or improved, at minimal or no increased cost. As a result, HOL has created a capital plan that paces investments in order to minimize rate impacts, while continuously improving efficiencies and productivity with respect to distribution planning and implementation. HOL is continuing to improve capital project prioritization, specifically in the areas of data collection and risk management.

Customer Consultations on Major Projects

HOL regularly consults customers with regards to major projects that will potentially impact customer property or neighbourhoods, such as cable replacement or distribution transformer replacement.

The consultation process first involves informing the potentially impacted customers of the pending work, followed by a customer open house aimed at creating open dialog. During the open houses, HOL staff informs customers on the scope, schedule and the general process to be undertaken to perform the work. It is also a venue for customers to provide their feedback and voice their concerns that staff can then immediately address. The open house strategy was developed based on feedback received from customers in the past and have since proven to enable a productive and successful project for both the customers and HOL. HOL believes, and it has been proven from these sessions that strong and open communication is essential with our customers. Customers have commented that they appreciate these consultation sessions as they provide a forum for discussion and airing their concerns, while allowing HOL to inform them of project needs and the concept of reliability.

Participation with Electrical Contractor Association

HOL actively communicates with the Electricity Contractor Association (ECA) of Ottawa to ensure strong communications between HOL and the numerous contractors that work in Ottawa. This need was identified by the ECA as part of the customer persona activity that HOL initiated in 2013. As a result, HOL now ensures any and all questions are answered and actively communicates new information to the ECA. Topics such as changes to the Conditions of Service are explained and discussed to ensure clear understanding of requirements. Feedback received in this continuous manner allows HOL planners to better understand future needs, timing of developments and issues and concerns around design standards and planning practices.

HOL Website

Customers are solicited for their direct feedback on HOL's corporate website, as well as, on the secured customer portal known as "My Hydro Link". Customers can send in their complaints and inquiries, the resolution of which, are tracked and managed by a complaint management

application. The use of complaint management software helps identify complaint trends and opportunities for improvement. As an example, one of HOL's previously rural areas was developed into a dense residential community. The rural area previously made use of a protection scheme known as fuse saving, which allowed a distribution circuit to experience momentary outages rather than longer sustained outages caused by factors such as animal contacts. As a result, long outages were avoided, but identifying the exact location and cause of the outage was more difficult. Based on customer feedback, HOL learned that these customers preferred experiencing a longer outage in order to determine the associated root causes and put in place location specific risk mitigation measures, such as animal guards. This highlighted that customers in different areas have different preferences and tolerances for dealing with outages. Regarding this particular issue, a dedicated feeder more suited for the now urban area was installed in late 2014 to provide improved reliability.

3.2.5 Prioritization of REG Investments

HOL prioritizes Renewable Energy Generation (REG) investments based on customer requests and follows regulated timelines for response and connection.

HOL strives to integrate all proposed residential and commercial customer generation projects into the grid. Several projects are proposed every year (see Table 3.3.1 for connected and committed generation) and HOL works with project managers and the customer to integrate the proposed generation into the distribution system. The process for accepting these projects involves: analyzing the generation capacity of the connecting feeder and interface transformer; verifying that the relevant station transformer can accept reverse flow; ensuring that the short circuit changes and voltage fluctuations will cause no material impacts on either the distribution or transmission grid; and reviewing the proposed single line diagram, electrical protection scheme and site plan for adherence to all HOL, ESA and OPA (now IESO) standards and requirements (Refer to 3.1.5.2 Ability to Connect New Generation). In the event that the proposed generation connection is not possible, HOL works with the customer to provide a solution. This solution may involve expanding the distribution system to meet customer needs or relocating the project to a more fitting property. Where work on the distribution system is required for the connection, the project is coordinated to ensure regulatory timelines are met while optimizing crew time.

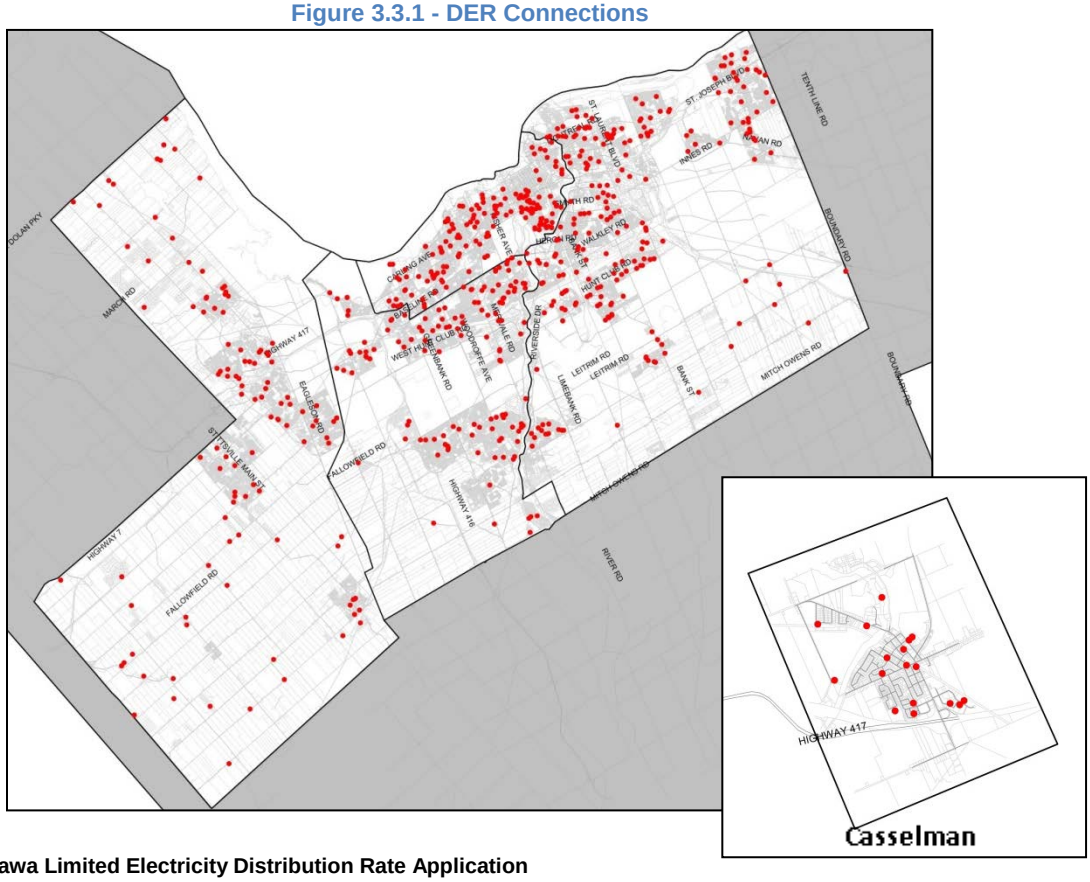
3.3 System Capability Assessment for Renewable Energy Generation

This section describes HOL's system capability to accommodate all Distributed Energy Resources (DER) including its the sub-set of Renewable Energy Generation (REG).

HOL is required by the Distribution System Code to assess generator connection requests of all fuel types, not just those defined as "renewable" in the Electricity Act, regardless of contract or program categories.

HOL currently has a number of connected generation facilities within the service area. These facilities have been connected and continue to be connected under various programs such as the OPA (now IESO) programs (FIT, HCI, PSUI-CDM, RESOP, HESOP), Net-Metering and Load Displacement. HOL also conducts system evaluations to accommodate a much broader group of generation connections classified as Distributed Energy Resources (DER), like large energy storage such as batteries and co-generation plants. The existing DER connections within HOL's service territory are shown in Figure 3.3.1.

Figure 3.3.1 - DER Connections



By the end of 2014 it is anticipated that HOL will have 678 DER connections of various sizes. The detail on number and total kilowatts of DERs connected by size and program are provided in Table 3.3.1.

Table 3.3.1 - 2014 DER Connections

Program / DSC Category	Large kW (qty)	Medium kW (qty)	Small kW (qty)	Micro kW (qty)	Total kW (qty)
Non-Renewable					
Load Displacement		9,249 (5)			**9,249 (5)**
Renewable					
FIT	-	-	10,792 (88)	-	**10,792 (88)**
HIC	-	18,080 (4)	500 (1)	-	**18,580 (5)**
Load Displacement	-	-	70 (1)	6 (3)	**76 (4)**
microFIT	-	-	-	4,619 (569)	**4,619 (569)**
Net-metered	-	-	-	18 (4)	**18 (4)**
RES 1		6,378 (1)			**6,378 (1)**
RESOP	-	10,700 (2)	-	-	**10,700 (2)**
Stand Alone	-	2,736 (1)	-	-	**2,736 (1)**
Total	**-**	**47,143 (13)**	**11,362 (90)**	**4,643 (576)**	**63,148 (679)**

Where the generation categories are defined in the Ontario Energy Board Distribution System Code (August 21, 2014), section 1.2 Definitions as:

Micro-embedded generation facility: name-plate rated capacity of 10kW or less

Small embedded generation facility: is not a micro-embedded generation facility with a name-plate rated capacity of 500kW or less in the case of a facility connected to a less than 15kV line and 1 MW or less in the case of a facility connected to a 15kV or greater line

Medium embedded generation facility: name-plate rated capacity of 10 MW or less and is more than 500kW in the case of a facility connected to a less than 15kV line and more than 1 MW in the case of a facility connected to a 15kV or greater line

Large embedded generation facility: name-plate rated capacity of more than 10MW

3.3.1 Applications Over 10kW

By the end of 2014, HOL will have a total of 102 connected DERs over 10kW, totalling 64.3 MW peak nameplate capacity. See Table 3.3.1, columns Large, Medium and Small.

3.3.2 Renewable Generation Forecast

Interest in generation projects within HOL's service territory has been steady over the historic years, and is anticipated to continue into the future. The trend has shown an increasing interest in Net-Metering and Load Displacement projects of various fuel types.

HOL has performed initial consultations or is currently (November 2014) completing assessments for:

- 69.35 MW of hydro-electric generation;
- 38 MW of co-generation (natural gas);
- 18.3 MW of solar photovoltaic ; and
- 16 MW of synthetic gas generation.

HOL is aware of 33 potential new projects under final FIT3 OPA evaluation totalling 8.68 MW of nameplate capacity. Currently, no existing restrictions are in place at the requested substation that would prevent connection.

Forecasts for DER connections are provided in Table 3.3.2 and are based on initial consultations and executed CIAs received and completed to date (November 2014). The initial consultations include those made with demonstrated higher level of intent under Net-Metering, Load-Displacement, IESO Energy Storage Procurement Request for Proposal (RFP) (one 4 MW applicant has been approved), and the OPA (now IESO) programs such as the PSUI, FIT 3, or Large FIT RFP. The executed CIAs have been for applicants under the OPA (now IESO) HESOP or PSUI program.

Table 3.3.2 - Forecasted DER Connections

Type	2015 (kW)	2016 (kW)	2017 (kW)	2018 (kW)	2019 (kW)	2020 (kW)
Co-Generation	9,723	3,250	-	-	25,000	-
Hydro-Electric	-	-	29,350	-	-	40,000
Solar PV	6,302	12,000	-	-	-	-
Synthetic Gas	-	-	16,000	-	-	-
Total	16,025	15,250	45,350	0	25,000	40,000

Capacity of the System to Connect DER as shown in Table 3.3.3 (last update December 5th, 2014) illustrates the capacity availability to connect Distributed Energy Resources at each HOL owned High Voltage Distribution Stations (HVDS). Note that if an HVDS has an open bus-tie switch capacity is provided per bus, and where the bus-tie is normally closed, it is provided by bus pair.

Overall, where HOL station limitations exist, they are limited by thermal capacity and not short circuit capacity, with the exception of Ellwood MTS and Nepean Epworth DS. When transformers are identified as having reverse flow capability, by manufacturer specification, (Bridlewood Q and Fallowfield Q) the limiting factor is the transformer capacity plus minimum station load. Otherwise, the limiting factor is simply the station minimum load.

Typically, more capacity at the stations is available for inverter based generation as opposed to spinning generation for two reasons:

- When reverse flow is the limiting factor, the minimum station load is higher between the 10AM to 3PM – the same period the solar generation nameplate capacity will likely be reached and the facility nameplate in capacity calculation is considered; and
- Short circuit contribution of inverter based generators is by rule of thumb 1.2 times the full load current and for spinning generation is considered to be 5 times the full load current.

The column label Connected & Committed represents all non-standby DER (renewable and non-renewable), that is already connected to the grid, committed for connection due to having an IESO or OPA contract, or HOL has issued a CIA and tentatively allocated, allocated, or reserved capacity.

Table 3.3.3 - Capacity for Generation at HOL HVDS

Station	Bus	Connected & Committed (kW)	Remaining Generation Capacity (kW)		Limiting Factor
			Equivalent Inverter Based Generation	Equivalent Spinning Generation	
Bridlewood MTS	B1	515	3,009	3,009	Minimum load
	Q	454	7,031	6,670	Transformation + Minimum load
Centrepointe DS	B1	45	1,730	736	Minimum load
	B2	30	882	167	Minimum load
Cyrville MTS	JQ	339	2,389	1,625	Minimum load
Ellwood MTS	JQ	335	1,905	457	Short Circuit
Fallowfield DS	J	9,131	0	2,454	Minimum load
	Q	9,224	11,614	5,292	Transformation + Minimum load
Kanata MTS	B1B2	1,124	18,475	17,317	Minimum load
Limebank MS	B1	87	3,485	2,408	Minimum load
	B2	468	6,238	4,616	Minimum load
Manordale DS	B1	23	1,493	639	Minimum load
	B2	34	1,808	823	Minimum load
Marchwood MS	J	865	7,420	5,425	Minimum load
	Q	295	7,519	6,654	Minimum load
Merivale MS	B1	84	1,667	644	Minimum load
	B2	22	1,878	1,385	Minimum load
Moulton MS	B1	80	5,638	3,729	Minimum load
	B2	-	4,614	4,099	Minimum load
Nepean Epworth DS	B	20	1,201	288	Short Circuit
	Q	12	2,398	1,112	Minimum load
Richmond South DS	B	300	1,628	866	Minimum load
Terry Fox MTS	J	4,105	0	1,929	Minimum load
	Q	24	2,450	1,959	Minimum load
Uplands MS	Z	228	9,219	8,388	Minimum load

Notes:

- Total Connected and Committed includes a reserve for future micro-generation projects;
- Committed projects are those that have an OPA Offer-of-Contract, received a CIA or have received and paid for a DER connection.

3.3.3 Constraints

Constraints to capacity for the connection of DER can occur due to legacy station power transformers not being able to accommodate reverse power flows as well as the short circuit capability of the station protection devices. To increase the short circuit limitations of the equipment, replacement is required with devices with higher ratings. Some station transformers have been operating for over 50 years and were intended to pass electricity only one way: from the transmission grid to the distribution system. At best, many of these units can allow connection of generation capacity up to the minimum of supplied load thereby not allowing electricity to flow back through the transformer and into the transmission grid. To eliminate this constraint, minimum load on the station transformer can be increased or the station transformer(s) can be replaced with newer, reverse flow capable units. As part of HOL's asset management plan, new or upgraded transformers being installed are standardized to allow for reverse flow in order to help eliminate the constraint through normal business practices.

There are currently six stations within HOL's service area that are either restricted or constrained for the connection of DER:

Slater TS

- HONI owned station
- Restricted due to short circuit handling capability being exceeded
- HOL is currently unaware of any plans to alleviate the restriction

Lisgar TS

- HONI owned station
- JY bus-pair is restricted due to thermal capacity being exhausted
- As a result of the IRPP Lisgar TS was identified for transformer replacement which will include transformers with reverse flow capability.

Hinchey TH

- HONI owned station
- Constrained by the legacy station transformers – no reverse flow capability
- HONI will be completing transformer replacements and station upgrade in 2016

- HONI has assured HOL that the newer transformers will be capable of some reverse flow

Lincoln Heights TD

- HONI owned station
- B bus-pair is constrained due to thermal capacity being exhausted for all but micro-generation projects
- HOL is currently unaware of any plans to alleviate the restriction

Fallowfield DS

- The J bus (half the station) is restricted to any further generation connection due to reverse flow limitations
- Remaining capacity has been reserved for an existing large generation customer that is currently undergoing the connection process
- Continued load growth at Fallowfield DS will increase the capacity available at the station
- Note that only half of the station is constrained as the second transformer was installed in 2013 and therefore has reverse flow capabilities, whereas the other, older unit does not.

Leitrim MS

- HOL owned single transformer station
- The station is thermally and short circuit constrained
- There is a 10 MW solar farm connected to this station
- Starting in 2015 HOL is undertaking station upgrades which will alleviate these constraints with the addition of a second transformer

3.3.4 Constraints for an Embedded Distributor

HOL does not have any embedded distributors within the service territory.

3.4 Capital Expenditure Summary

This section provides the overview of HOL's total capital expenditures for the period from 2011 through 2020, along with discussions on yearly and trend variances.

3.4.1 Capital Spending Overview

Overall capital expenditures are outlined in Table 3.4.1, showing the budget and actuals for the years 2011 through 2020.

HOL plans and budgets work by Capital Program (see section 3.1); therefore, the variances described in the following sections will be explained in terms of these Capital Programs.

The tables outlined in the following sections list the capital expenditures for the period 2011 through 2020. ~~At the time of writing (November 2014) the final numbers for 2014 actuals are not available and have therefore been based on Q2 forecast: 6 months of actual costs and 6 months of forecasted costs.~~ For the 2015 costs, no actual expenditures have been included in this report.

Table 3.4.1 - Capital Expenditure Summary

Category	Historical (Previous Plan & Actual)														
	2011			2012			2013			2014 ~~Q2*~~			2015		
	Plan	Act.	Var	Plan	Act.	Var	Plan	Act.	Var	Plan	Act.	Var	Plan	Act.	Var
	$M		%	$M		%	$M		%	$M		%	$M		%
System Access	30.2	31.6	5%	34.5	30.9	~~-2%~~ 11%	36.9	37.7	~~-11~~ 2%	40.7	~~39.0~~ 35.5	~~-8%~~ -13%	35.3	-	-
System Renewal	26.7	27.8	4%	27.4	29.6	~~10%~~ 8%	23.4	29.5	~~8%~~ 26%	32.8	~~37.0~~ 37.4	~~-7%~~ 14%	40.0	-	-
System Service	25.5	26.7	5%	21.5	21.4	~~20%~~ 1%	25.1	23.9	~~-1%~~ -5%	23.1	~~21.8~~ 19.3	~~-10%~~ -16%	20.8	-	-
General Plant	20.6	10.2	-50%	35.9	27.2	-24%	43.6	40.5	~~-24%~~ -7%	22.8	~~18.7~~ 32.8	~~-11%~~ 44%	20.9	-	-
Total	**103.1**	**96.3**	**-7%**	**119.3**	**109.0**	**-9%**	**129.0**	**131.6**	~~**9%**~~ **2%**	**119.4**	~~**116.5**~~ **125.0**	~~**-9%**~~ **5%**	**117.0**	-	-
System O & M	N/A	N/A	N/A	N/A	24.9	N/A	N/A	25.2	N/A	N/A	27.1	N/A	29.5	N/A	N/A

~~*Note that 2014 Actuals are based on Q2 forecast~~

Table 3.4.2 - Capital Expenditure Forecasted Spend

Category	Forecast (Planned)				
	2016 (test)	2017	2018	2019	2020
	$M	$M	$M	$M	$M
System Access	36.3	35.2	35.1	35.8	36.6
System Renewal	41.0	31.8	36.5	36.0	35.7
System Service	22.2	34.0	29.5	30.5	33.3
General Plant	45.9	48.1	18.3	18.7	14.0
Total	**145.4**	**149.1**	**119.4**	**121.0**	**119.5**
System O & M	30.9	N/A	N/A	N/A	N/A

3.4.2 System Access

System Access investments are "modifications (including asset relocation) to a distributor's distribution system that a distributor is obligated to perform to provide a customer (including a generation customer) or group of customers with access to electricity services via the distribution system" as *per Section 5.1.1 of Chapter 5*.

Spending in the System Access Capital Programs is focused around:

- Relocation of existing plant due to third party agency (the cities of Ottawa and Casselman, Ministry of Transportation of Ontario, National Capital Commission) infrastructure projects;
- Costs associated with the connection of new residential and commercial customers;
- Expansion of HOL's distribution system to meet a specific customer or developer's needs;
- Connection of new generation customers under various provincial programs such as microFIT, FIT and RESOP;
- Connection of one-off residential and small commercial infill connection requests that do not fall under the dedicated Residential and Commercial Capital Programs;
- Replacement of damaged assets caused by a third party; and
- New and replacement meter installations.

Details of these Capital Programs have been outlined in section 3.1.1.

3.4.2.1 Historic Expenditures

The following section outlines HOL's System Access Capital Programs and projects from 2011 through 2020 and discusses the variance in spending over the 10 years. As mentioned in section 3.1.1 System Access.

System Access expenditures are mandated by legislation. While HOL strives to ensure the expenses in this Investment Category are completed as efficiently as possible, HOL does not control the timing of projects. While every attempt is made to predict and budget the expenses, the actual implementation is not within HOL's control. Budgeting is based off of historical

spending and known large projects or changes in legislative requirements (e.g. Green Energy Act).

Table 3.4.3 - System Access Expenditure Summary

Investment Category / Capital Program	2011		2012		2013		2014		2015
	Act.	Var.	Act.	Var.	Act.	Var.	Act.*	Var.	Plan
	$'000	%	$'000	%	$'000	%	$'000	%	$'000
System Access	**31,635**	**5%**	**30,868**	**-11%**	**37,675**	**2%**	~~**39,010**~~ **35,542**	~~**-4%**~~ **-13%**	**35,275**
Plant Relocation	7,743	39%	5,942	-24%	10,005	-13%	~~9,437~~ 9,207	~~-19%~~ -21%	7,814
Residential	7,247	35%	6,278	34%	6,573	37%	~~5,985~~ 5,080	~~-1%~~ -16%	6,720
Commercial	9,159	25%	11,892	99%	10,634	47%	~~9,342~~ 7,289	~~-1%~~ -23%	12,279
System Expansion	3,276	-28%	1,675	-86%	5,710	-30%	~~10,144~~ 9,464	~~8%~~ 0%	3,727
Stations Embedded Generation	190	204%	1,181	2680%	64	-81%	~~277~~ 259	~~2%~~ 4%	376
Infill & Upgrade	3,081	-1%	2,731	-10%	3,178	-3%	~~2,857~~ 3,291	~~-2%~~ 13%	3,075
Damage To Plant	826	-5%	798	4%	1,349	64%	~~840~~ 870	~~-2%~~ 2%	1,120
Metering	112	-97%	370	-31%	160	-81%	~~130~~ 81	~~-3%~~ -39%	163

Historical spending in System Access has steadily increased from 2011 through 2014. While some Capital Programs have remained consistent, others have seen considerable growth causing the overall trend to show a steady increase in spending in the category. While attempts are made to budget for both the historical trending and known major projects in System Access,

variances from the budget do occur on a regular basis, and are typically offset by the other Capital Programs within this category.

Plant Relocation

HOL has seen a steady increase in the spending for Plant Relocation mainly due to the City of Ottawa's Light Rail Transit project (LRT). This project was budgeted based off of the City of Ottawa's LRT project schedule, which has seen a number of revisions and project changes over the course of HOL's involvement. The changes in project plan have been due to decisions made by the City of Ottawa and not HOL, but these changes have impacted both the timing and scope of work required.

Residential

Historically, residential subdivisions in HOL's territory have followed a 7-10 year rolling trend that has been consistent with the provincial and national averages since amalgamation, with the noted exception of 2011. Ottawa's territory trending has been slightly higher than the provincial and national average. As of 2012, and into 2013, subdivision development is in a flat line state and will likely continue until 2014 when the City of Ottawa finalizes its review of the Official Plan regarding development lands. There has also been a shift in development housing trends over this timeline due to intensification policies: there are more blocks within subdivisions being used for high density housing (Stacked Townhomes) on private streets.

Commercial

New Commercial Development has remained strong in Ottawa in recent years, including 2013 ~~as actual costs are expected to exceed the budget by approximately 5 million dollars~~ due to developer demand. The recent economic downturn in Canada has had little effect on Ottawa as it is largely government and high tech based. The 2014 ~~is expected to remain fairly consistent with 2013 results, new commercial development is still increasing as a result of developer demand.~~ expenditures were below the levels seen from 2011 throough 2013, however the overall trend has seen a relatively consistent spending profile.

System Expansion

The actual costs for system expansion have varied over the 5 year time frame as requests have been made to HOL. The budgets for system expansion are based on historical trends and

expected projects. HOL works with the relevant City of Ottawa departments, as outlined in section 3.1.11.1, to ensure that the forecasts are in line with the City of Ottawa. The timing of these projects, and therefore the actual costs are driven by the third parties and not controlled by HOL. HOL works with the third parties to determine realistic estimates for timing; however, delays do occur due to external reasons and cannot always be controlled by HOL.

Embedded Generation

Costs associated with distributed generation connections have shown a steady increase since 2011 with the exception of 2012. Work associated with OPA's (now IESO) FIT program and the Green Energy Act had been fairly low at the start of the program but has been steadily increasing with all projects associated with FIT 1.0 to be completed in 2015 which has caused the increase in spend in 2013 and 2014. HOL has not received any projects under the FIT 2.0 release. A large RESOP project for the Green Soldiers 10MW solar farm was located just beyond HOL's service territory and included the construction of a new 27.6kV overhead pole line and communication tower at Leitrim MS station to allow for protection upgrades. In order to serve the customer, a service area amendment was completed with Hydro One. This project represented a cost of $1.2M in 2011 and 2012 which is more than all other distributed generation projects from 2011 to 2015 combined.

Infill & Upgrade

Infill services remain strong due to the City's Official Plan which encourages urban infill developments. HOL anticipated that the demand for these installations would remain strong through 2015. The actual cost for infill services has remained consistent over the 5 year time frame as Ottawa has been isolated from any slowing of the home market. The budgets for infill services are based on historical trends and expected projects. HOL works with the relevant City of Ottawa departments, as outlined in section 3.1.11.1, to ensure that our forecasts are in line with the City of Ottawa. The timing of these projects, and therefore the actual costs are driven by the third parties and are not controlled by HOL. HOL works with the third parties to determine realistic estimates for timing, however delays do occur due to external reasons and cannot always be controlled by HOL.

Damage to Plant

Due to the largely unknown and variable nature of the Damage to Plant Capital Program historical trends are used as the basis for budgeting and forecasting. Since 2007, Damage to Plant expenditures have remained relatively stable year over year. The vast majority of damages consistently occur to overhead and underground transformers, and to wooden poles. The impact of increasing material and labour costs has offset gains made in reducing volumes and/or severity of incidents. As such, 2014 & 2015 volumes and costs are expected to remain consistent with prior years.

Metering

The work consists of recertification of meters to ensure their accuracy and extend either the meter's serviceable life or that of a representative sample of meters through compliance sampling. This work all but disappeared through the smart meter installation years from 2006-2011 and into 2012. Metering has been proactively pre-inspecting compliance sample lots to attest to their quality and in 2014 compliance sample testing will be conducted on those meters installed in 2006 to extend their life beyond the initial seal period of 10 years. HOL does this in advance of the 2016 seal expiry period to flatten out production as one third of the whole system meter population was installed with contractors in the fall of 2006, representing 96,000 meters.

3.4.2.2 Forecast Trend

Table 3.4.4 - System Access Forecasted Spend

Investment Category / Capital Program	Forecast (Planned) $'000				
	2016	2017	2018	2019	2020
System Access	**36,263**	**35,156**	**35,132**	**35,835**	**36,551**
Plant Relocation	7,620	7,773	7,928	8,087	8,248
Residential	6,889	7,027	7,167	7,311	7,457
Commercial	13,423	13,042	12,576	12,827	13,084
System Expansion	3,479	2,366	2,413	2,462	2,511
Stations Embedded Generation	377	384	392	400	408
Infill & Upgrade	3,160	3,223	3,288	3,353	3,420
Damage To Plant	1,148	1,171	1,195	1,219	1,243
Metering	167	170	173	177	180

The forecasted spending in the System Access category is expected to remain at consistent levels through to 2020. HOL expects that the economy in Ottawa will remain steady over the next five years, and work associated with the System Access Category will remain at the levels seen since from 2011 through 2015.

- Plant Relocation costs are expected to remain at the elevated costs seen since 2013 as a result of the LRT project. This project has represented a large increase in the relocation costs for HOL. While the first phase of LRT is expected to be completed in 2018, the City of Ottawa has expressed plans to continue directly into the second phase of the project. This combined with a continued focus on infrastructure investments by the City and other agencies HOL expects the spending to remain at the current levels through to 2020 and beyond.
- With the continued strength of the Ottawa community, HOL is expecting that the customer connection needs in Residential, Commercial and Infill & Upgrade Capital Programs will remain consistent with the levels from 2011 through 2015.
- System Expansion is expected return to historical values seen in 2011 and 2012. With the completion of the Phase 1 of the City of Ottawa's LRT project expected in 2018, HOL plans on completing the required work for this project in 2016. Following that, for future phases, there are no details of the requirements for HOL, and as a result no costs have been budgeted past 2016.
- Stations Embedded Generation is expected to remain at the consistent levels experienced in 2014 and 2015. With the transmission constraints removed from the Ottawa area by Hydro One, it is expected that the level of interest for these connections will remain at the current levels.

3.4.3 System Renewal

System Renewal investments "involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services" as per Section *5.1.1* of Chapter 5. Projects outlined in the System Renewal Investment Category have been identified as part of HOL's Asset Management Process.

Spending in the System Renewal Capital Programs is outlined in section 3.1.2 and are focused around:

- Replacement of end of life and obsolete station equipment such as power transformers, switchgear and protection devices;
- Refurbishment of station building structures and facility systems;
- Replacement of end of life distribution assets such as poles, distribution transformers, cables and switches;
- Replacement of in service failed assets through the Plant Failure Capital Program; and
- Upgrades to end of life meters and meter technology.

3.4.3.1 Historic Expenditures

The following section outlines the capital expenditures in the System Renewal category from 2011 through 2020. Projects contained in the in System Renewal and System Service categories are determined through HOL's capital expenditure planning process outlined in section 3.2. variances in this category are tracked and approved though HOL's change order request process. This process documents changes in project plans or costs associated with each individual project. This process allows HOL to track and adjust the progress of the sustainment project to ensure that spending is completed as close as possible to the planned budget. Any large variance in the plan can be identified and allow for adjustment of the plan to keep the asset management plan on track.

Table 3.4.5 - System Renewal Historical Spend

Investment Category / Capital Program	2011		2012		2013		2014		2015
	Act.	Var.	Act.	Var.	Act.	Var.	Act.*	Var.	Plan
	$'000	%	$'000	%	$'000	%	$'000	%	$'000
System Renewal	**27,778**	**4%**	**29,628**	**8%**	**29,540**	**26%**	~~**36,997**~~ **37,408**	~~**13%**~~ **14%**	**40,048**
Stations Asset	5,097	-9%	8,475	10%	9,154	48%	~~14,493~~ 13,327	~~11%~~ 2%	17,200
Stations Enhancement	2,046	-7%	1,067	-66%	906	-38%	~~825~~ 815	~~-16%~~ 17%	679
Distribution Asset	20,512	9%	19,701	22%	18,992	23%	~~21,263~~ 22,898	~~16%~~ 25%	21,756
Metering	122	37%	385	-6%	488	33%	~~416~~ 369	~~1%~~ 10%	412

Historical spending in the System Renewal has fluctuated over the past five years, but overall has seen an increase in the spending trend, as in the other capital categories. Both of the largest Capital Programs (Station Assets and Distribution Asset) are for the replacement of existing aging infrastructure. The need for these projects has been outlined in section 2.3 Asset Lifecycle Optimization Policies and Practices.

Stations Asset

The investments in Stations Asset have seen a marked increase year over year in the past 5 years. While attempts to maintain overall spending on major station projects (Stations Capacity, Transformer Replacement and Switchgear Replacement) consistent year over year, it is not possible to smooth the spending over all years of the Capital Programs. The individual projects are budgeted in an attempt to maximize the efficiency of the project and can cause the timing of costs required for these multiyear projects to fluctuate.

Stations Enhancement

The investments in Stations Enhancements have seen a reduction from 2011 to ~~2013~~ 2014 with the completion of the Stations Transformer Cooling Fan and Porcelain Insulator projects. The spending levels in ~~2014 and~~ 2015 are planned remain consistent trough to 2020.

Distribution Asset

The spending in Distribution Assets has shown a more consistent increase over the 5 years. Spending in the Capital Program has continued to focus on Pole and Cable Replacement Projects along with the Plant Failure projects.

Spending in System Renewal in 2011 was within 4% of the budgeted amount, but some variances did occur in various Capital Programs.

- Stations Asset was 9% below original budget due to contractor and vendor delays causing spending on two Station Switchgear Replacement projects (Richmond North DS and Bridlewood Breaker Refurbishment) to be delayed and pushed these costs forward one year into 2012.
- Distribution Assets was 9% off of budget, however under this Capital Program there were a number of larger variances over and under the planned budget. In the pole replacement program a number of projects were completed under the estimated amount which caused a decrease in the expenditures compared to the budget. The Pole Replacement, Elbow and Insert Replacement and Distribution Transformer replacement programs were faced with contractor and labour restrictions that caused some of the work to be pushed into 2012.
- Offsetting these decreases in spend in System Renewal in 2011 was the spending in Plant Failure which saw a year end cost 141% above the original budget. Spending on Plant Failure is due to assets that are not replaced proactively before they reach their functional end of life and fail while in service. As outlined in section 2 Asset Management Process, many of the HOL's assets are reaching end of life. Even though HOL is increasing spend on proactive asset replacement to offset the anticipated equipment reaching end of life and levelize replacement spend, HOL continues to experience failure of in service equipment. The spending of $5.1M has been seen in

2011 through 2014; however, HOL has continued to budget at a lower amount. HOL focuses on replacing assets in a proactive manner through planned projects as outlined in our Asset Management Process in Section 2.1. This focus on proactive replacement is expected to reduce the required spend on plant failure. The lower budget also allows planning for an adequate amount of sustainment work for our crews to meet available labour hours, allowing for readjustment if there is an increase in the Plant Failure work that cannot be handled within the capital budget or labour and contractor availability. The level of plant failure spend is continuously monitored throughout the year and the capital budgeted projects are adjusted accordingly.

Spending in 2012 was 8% over budget for the System Renewal category.

- Stations Assets spending was 10% above budget mainly due to increased spending in stations transformers. Scope Increases associated with the transformer replacement at Clyde UC and Barrhaven DS were the main reasons for the Capital Program tracking over the original budget. Increased civil construction costs at Clyde US were caused by unforeseen removal of legacy underground structures and increased safety requirements. It was determined that the Barrhaven DS project could be done more efficiently if the timing of the project was condensed, which pulled costs into 2012 that were originally planned for 2013.
- Costs associated to the Stations Refurbishment Capital Program for protection and equipment upgrades associated to the Green Energy Act (GEA) were originally budgeted to the System Renewal Investment Category. The budgeting was done early on in the GEA implementation when the true requirements of the program were not yet known. It was later determined that the upgrades required at the stations were already part of HOL's Stations Asset Capital Program and the costs therefore would not be required.
- Distribution Asset spending was over the original budget by 22% and again was mainly due to spending in the Plant Failure Capital Program, for similar reasons as those discussed for 2011.

System Renewal spending in 2013 was 26% above the original budget; this was offset by under spending in both General Plant and System Service. Sustainment (System Renewal and System Service) as defined by HOL was 11% over the original budget as a whole.

- Stations Assets was over spent by 48% in 2013 mostly due to increased spending in the Stations Transformer Replacement Budget Program. Carry over associated with the Clyde UC transformer replacement project was the main contributing factor. This was a direct result of the increased scope that was highlighted in the 2012 spending. For the Beechwood UB transformer project, the feeder reconfiguration project that was identified for future years was added to the station project scope. This combined with higher contractor costs than anticipated also contributed to the increased spending in the Stations Replacement Budget Program.
- Distribution Asset spending was over the original budget by 23% and similarly to 2011 and 2012, was mainly due to spending in the Distribution Plant Failure Budget Program. The reasons for this are the same that were discussed for 2011. Spending was in line with the values that have been experienced from 2011 through 2014.

2014 spending in the System Renewal Investment Category ~~is expected to be 13%~~ was 14% over the original budget. ~~This is based off of the 6 months of actuals and 6 months of forecasted expenditures.~~ Sustainment (System Renewal and System Service) as defined by HOL was only ~~5%~~ 1% over the original budget as a whole.

- The majority of the ~~forecasted~~ spending variance is due to spending in Station Plant Failure in the Stations Asset Capital Program which is expected to be 11% over the original budget. The one station transformer at Leitrim MS was required to be replaced due to failure, as identified through dissolved gas analysis. This replacement is expected to continue into 2015.
- Distribution Asset spending was over the original budget by ~~16~~ 25% and similarly to 2011 through 2013, was primarily due to spending in the Plant Failure Budget Program. The reasons for this are the same as those discussed for 2011. Spending was in line with the values that have been experienced for the past three years.

3.4.3.2 Forecast Trend

Table 3.4.6 - System Renewal Forecasted Spend

Investment Category / Capital Program	Forecast (Planned) $'000				
	2016	2017	2018	2019	2020
System Renewal	**41,033**	**31,823**	**36,491**	**35,980**	**35,718**
Stations Asset	16,338	11,815	14,048	15,203	14,186
Stations Enhancement	597	634	731	662	691
Distribution Asset	23,683	17,828	20,128	18,492	19,179
Metering	415	1,547	1,584	1,623	1,662

Overall, when combined, spending in System Renewal and System Service is expected to increase at 3% annually from 2016 through 2020. The main driving factor for fluctuations in the category spend over the 5 years is due to timing of the major station projects. The decrease in spend in 2017 is due to the increased spending in the Stations New Capacity Budget Program in order to maintain overall sustainment spending consistent year over year. A continued focus will be seen through to 2020 and beyond on replacements of the critical assets as outlined in section 2.2.3 Asset Demographics and Condition. HOL will continue to replace major station and distribution assets on a focused basis as has previously been the case.

- Station transformers and switchgear will remain consistent with the spending levels seen since 2011;
- Distribution asset including poles, cable and switches will also remain consistent. A large civil infrastructure project along Carling Avenue is planned for 2016 which will see a one year increase in HOL's Civil Rehabilitation Budget Program.
- An increased focus on spending for the Remote Disconnect Smart Meter Budget Program is planned for 2017 and will continue through to 2020.

3.4.4 System Service

System Service investments are "modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future electricity service requirements" as per Section *5.1.1* of Chapter 5.

Spending in the System Service Investment Category is focused around:

- Stations Capacity Upgrades covers the building of new or rebuilding of stations for the addition of transformation capacity or supply;
- Distribution Enhancements includes a range of system betterment projects. Included in this Capital Program are Line Extensions and System Voltage Conversions projects; and
- HOL's Automation Capital Program which include upgrades to the SCADA systems and installation of automated switches in the distribution and devices in stations.

3.4.4.1 Historic Expenditures

The following section outlines the capital spending in the System Service category from 2011 through 2020. Projects contained in the in System Renewal and System Service categories are determined through HOL's capital expenditure planning process outlined in section 3.2. Variances in this category are tracked and approved though HOL's change order request process. This process documents changes in project plans or costs associated with each individual project. This process allows HOL to track and adjust the progress of the sustainment project to ensure that spending is completed as close as possible to the planned budget. Any large variance in the plan can be identified and allow for adjustment of the plan to keep the asset management plan on track.

Table 3.4.7 - System Service Historical Spend

Investment Category / Capital Program	2011		2012		2013		2014		2015
	Act.	Var.	Act.	Var.	Act.	Var.	Act.*	Var.	Plan
	$'000	%	$'000	%	$'000	%	$'000	%	$'000
System Service	**26,716**	**5%**	**21,362**	**-1%**	**23,917**	**-5%**	**~~21,753~~ 19,298**	**~~-6%~~ -16%**	**20,806**
Stations Capacity	19,170	16%	11,838	-2%	13,198	-13%	~~6,223~~ 4,352	~~30%~~ 9%	2,187
Distribution Enhancements	6,226	-12%	8,375	23%	~~10,319~~ 10,332	13%	~~14,961~~ 14,587	-16% 18%	15,176
Automation	1,320	-33%	1,150	-58%	400	-52%	~~569~~ 359	~~3%~~ -35%	3,444

Historical spending in the System Service category has fluctuated within each Capital Program over the past five years, but overall has shown a steady trend. The largest contributor to the costs in System Service category can be attributed to Stations Capacity and Distribution Enhancements Capital Programs. These programs are designed to build out the distribution system to efficiently serve the customer at the best possible value. The need for these projects has been outlined in 3.1.3 System Service.

Stations Capacity

The investments in Stations Capacity has decreased over the past five years which is due to the completion of three major station builds at Ellwood MTS, Beacon Hill DS and Terry Fox MTS. These projects are in addition to the expansion of a number of other stations through the installation of additional transformers. While attempts to maintain overall spending on major station projects (Stations Capacity, Transformer Replacement and Switchgear Replacement) consistent year over year, it is not possible to smooth the spending over all years of the Budget Programs. The individual projects are budgeted in an attempt to maximize the efficiency of the project and can cause the timing of costs required for these multiyear projects to fluctuate.

Distribution Enhancements

The spending in Distribution Enhancements has increased gradually since 2011. The largest increase has been seen because of increased spending in the Voltage Conversion Budget Program which has been focused in the Woodroffe TS, Kilborn DS and South Nepean areas.

Line Extensions have fluctuated over the 5 years since 2011, but the majority of these projects are tied to the timing of the completion of Station New Capacity projects. Details on these projects can be found in section 3.5 Justifying Capital Expenditures.

Automation

The Automation Capital Program have decreased in 2013 and 2014 as automation switch installations have become part of our normal course of business. 2015 is the first year of HOL Telecom Plan implementation. The details of this project are outlined in Attachment B-1(A). This project will continue to 2024.

Spending in System Service in 2011 was 6% below the budgeted amount, but some larger variances did occur in various Capital Programs.

- Distribution Enhancements was 12% under the budgeted amount for 2011, with the majority of the variances being in the Line Extensions Budget Program. The variance in this Budget Program was due to both efficiencies in construction and a portion of the work being pushed into 2012.
- The Automation Capital Program spending was below budget due to the cancelation of one project in the SCADA Upgrade Budget Program. The MyOASIS project was canceled after a detailed review revealed that it was not going to deliver the desired outcomes.

2012 System Service spending was very close to budget at 1% below the budgeted amount of $21M.

- Distribution Enhancements was 23% over the original budget in 2012 due to carry over of projects from 2011 in the Line Extension Budget Program and an increase in the scope for the voltage conversion project at Upland DS.
- The Automation Capital Program spending was below budget due to delays on the SCADA Upgrade Budget Program and delays of control boxes for automated distribution switches.

2013 System Service spending was again close to budget at 5% below the original amount.

- Progress payments for the new Switchgear at Limebank MTS and contractor delays for the construction of the expanded Casselman DS led to the spending in Station Capacity to be 13% below the original budgeted amount of $15M.
- The reasoning for the increase in the spending for Distribution Enhancements was due to an increase in the scope for the Woodroffe Voltage Conversion project. Some of this increase was offset by the delays in three line extension projects. Delays in the City of Ottawa's Strandherd Bridge project delayed the installation of new feeder ties across the Rideau River and Work along the Alta Vista Transit Corridor was delayed to 2014 due to HOL budget and resource constraints.

~~The forecasted spending for 2014 is expected to be in line with the budget with a 6%- variance from the budget.~~ 2014 System Service spending was 16% below budget.

- Stations Capacity spending ~~is forecasted to be over budget. The majority of these costs are due to the carryover of in spending from Hinchey TH from 2013~~ was under budget due delays in the Hinchey TH project caused by Hydro One. Hydro One has incurred delays on their portion of the project, which has not allowed HOL to move forward with procurement and consutruction as scheduled.~~.~~ An increased scope in the Casselman DS project to upgrade the second bank has ~~also led to a large increase in the Stations Capacity Capital Program~~ offset some of these dealys.
- A number of Line Extension projects have been delayed due to coordination with the City of Ottawa's LRT project. The planned work for the LRT has caused a delay to the completion of a number of projects to ensure HOL work coincides with the City's plans.

3.4.4.2 Forecast Trend

Table 3.4.8 - System Service Forecasted Spend

Investment Category / Capital Program	Forecast (Planned) $'000				
	2016	2017	2018	2019	2020
System Service	**22,235**	**33,957**	**29,518**	**30,473**	**33,314**
Stations Capacity	5,676	15,272	10,464	14,441	15,626
Distribution Enhancements	11,290	12,282	14,175	12,829	13,394
Automation	5,269	6,403	4,880	3,202	4,295

Overall, when combined, spending in System Renewal and System Service is expected to increase at 3% annually from 2016 through 2020. The main driving factor for fluctuations in the category spend over the 5 years is due to timing of the major station projects. Spending in the System Service category is expected to increase in 2017 and continue at the elevated levels through 2020. The requirement for the Stations Capacity and Distribution Enhancement Capital Programs has been outlined in section 3.1.3

HOL will continue to build and enhance our stations while developing distribution feeders and ties as we have been since before 2011 including:

- Station capacity upgrades including the rebuild of Richmond South DS, building of a new transmission station in the south region to supply the growing City along with additional transmission upgrades to improve reliability;
- Build new and extend feeders to connect the new capacity with the customers and load, while focusing on removing stations and their associated distribution assets through targeted voltage conversions;
- Continuation of the Telecom Plan project started in 2015 through 2020 with completion in 2024. The details of this project are outlined in Attachment B-1(A).

3.4.5 General Plant

General Plant investments are “modifications, replacements or additions to a distributor’s assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities” as *per Section 5.1.1* of Chapter 5.

In General Plant, there are two major funding requirements:

1) Life cycle funding requirements for fleet replacement, facilities, tools, and information technology asset replacement have also been forecast to 2020. The investments are essential to meet the operational needs.
2) New technology initiatives have been identified in the 2015 to 2020 planning horizon. The business case for each initiative have been reviewed and approved by the Executive Management Team. Examples include mobile workforce management

software, asset planning software, JD Edwards system upgrades, and automated power outage system upgrades. Each of these initiatives is required to maintain the integrity of our data, to facilitate productivity improvements through automation, and/or to position HOL for the next phase of smart grid transformation in the planning horizon.

The following section outlines the capital spends in the General Plant from 2011 through 2020.

3.4.5.1 Historic Expenditures

The following section outlines HOL's System General programs from 2011 through 2020 and discusses the variance in spending over the 10 years. Expenditures and variances are tracked regularly by HOL's management team and are adjusted to align with any changes in the Corporate Strategic Objectives.

Table 3.4.9 - General Plant Expenditure Summary

Investment Category / Capital Program	2011		2012		2013		2014		2015
	Act.	Var.	Act.	Var.	Act.	Var.	Act.~~*~~	Var.	Plan
	$'000	%	$'000	%	$'000	%	$'000	%	$'000
General Plant	**10,215**	**-50%**	**27,190**	**-24%**	**40,484**	**-7%**	~~**18,742**~~ **32,754**	**44%**	**20,850**
Buildings - Facilities	767	-51%	380	-60%	380	-52%	~~426~~ 534	1%	688
Customer Service	3,818	-65%	10,365	0%	13,389	2%	~~5,839~~ 5,407	3%	2,450
ERP System	950	-29%	933	-28%	478	-24%	~~329~~ 38	-96%	1,547
Fleet Replacement	2,024	-15%	2,542	-5%	3,056	-26%	~~1,441~~ 1,278	-38%	1,537
IT New Initiatives	296	-55%	578	-19%	57	-95%	~~1,584~~ 1,204	-21%	2,111
IT Life Cycle & Ongoing Enhancement	1,122	-43%	2,440	19%	3,076	33%	~~2,821~~ 2,879	7%	1,970
Operations Initiatives	356	-44%	683	54%	242	-67%	~~3,011~~ 2,946	280%	2,756

Tools Replacement	580	-17%	568	-18%	539	-19%	~~386~~ 319	-47%	512
Hydro One Payments	-	-	1,116	N/A	6,358	11%	~~2,453~~ 17,682	371%	2,347
Facilities Implementation Plan	302	-20%	7,586	-54%	12,909	-10%	~~453~~ 468	~~-91%~~ 90%	4,933

~~*Note that 2014 Actuals are based on Q2 forecast~~

Historical spending in the General Plant investments has seen a marked increase from 2011 through 2015 from the implementation of HOL's Facilities Implementation Plan which is outlined below. Outside of this program the spending has remained consistent over the past 5 years with the exception of 2011 and 2013. Spending in 2011 was significantly below budget due to timing of cost of service application and the pending rate approval. All General Plant capital spending was cut to a bare bone. 2013 saw an increase in spending in the Customer Service Capital Program which is outlined below. Overall the General Plant Investment Category has had little variance to budget with the exception of the Facilities Implementation Plan which has been under budget for the past years. The details of these variances are outlined below.

Buildings – Facilities

Spending in the Building – Facilities Capital Program have been pared back due to the implementation of the Facilities Implementation Plan.

Customer Service

The largest contributor to the costs in General Plant was attributed to the Customer Care and Billing System (CC&B) Upgrade started in late 2010, went live in 2014. The Customer Information System was going to reach end of life in 2013 and no longer supported by its vendor. Therefore the company invested on the upgrade of the new system to ensure billing is properly supported. Spending variance from budget was due to timing of project milestones and delivery.

ERP System

Spending in the ERP System Capital Program remained relatively consistent over the past 5 years. There is an increase in spending in the ERP Capital Program in 2015. The Enterprise

Architecture Program is a multi-year project to connect all the individual software applications and improve operational effectiveness and the JDE Application Upgrade will begin (details can be found in Attachment B-1(A)). In the past three years, the spending for ERP System was below budget due to internal resource issue. Several key enhancements are reprioritized for the upcoming ERP Upgrade.

Fleet Replacement

Life cycle replacements were steady with a slight increase in 2013. The spending in 2014 and 2015 reduced due to the vehicle end of life schedule caught up with the increase in 2013. Some vans and trucks ordered in 2013 were delivered in 2014, therefore 2013 spending was below budget.

IT New Initiatives

This program focuses on initiatives to optimize business operations including Document Management System, Enterprise Architecture Program, and Data Management System. The introduction of Document Management System to ensure documents for legal, business, health, safety, environmental are managed in accordance with legislative compliance and ISO requirement. The Asset Planning software is to improve capital planning process and ensure the most optimized capital investment decisions are made for the company and the customers. The project is ~~expected to be complete in 2015~~ completed in 2014. Historical spending was below budget due to internal resources redeployed for other IT Life Cycle & Ongoing Enhancement projects.

IT Life Cycle & Ongoing Enhancements

The IT Life Cycle & Ongoing Enhancements Capital Program has a slight increase over the past 5 years. 2012 and 2013 spending exceeded budget due timing of spending i.e. 2011 projects implemented in 2012. Also some of the new initiative components were embedded into the ongoing enhancements. Combined the two programs, the spending was in line with budget projection.

Operations Initiatives

Operations Initiatives have remained constant from 2011 through to 2013. The spending is planned to increase in 2014 and 2015 with the focus on the next productivity initiative –Mobile

Workforce Management software (project details can be found in Attachment B-1(A)). 2011 spending was low due to the Radio System Replacement project budgeted in 2011, but completed in 2012. 2013 variance is mainly explained by a planned GIS (OMS-AMI Meter Ping) project cancellation due to some technical issues with AMI communication infrastructure.

Tools Replacement

The Tools Replacement Capital Program has remained relatively unchanged over the past 5 years with spending being at a consistent level under the budget.

Hydro One Payments

Starting in 2012, capital contributions to intangible assets purchased from Hydro One in conjunction with HOL's major station projects accounted for under the General Plant account. Prior to 2012, costs associated with these investments were tracked under the separate System Renewal or System Service budgets. These budget amounts and timelines for these projects are based off of the original signed contracts between Hydro One and HOL, but timing can move these payments out of the budgeted year. The only payment in 2012 was for HOL's Hinchey TH project which was originally budgeted under Stations Capacity in the System Service category.

2014 spending was ~~well under~~ over the budget, while spending was over budget, there were protions of the spending that were under the budgeted amounts. Two payments that were moved to 2015 ~~This was due to the delay of two projects,~~ caused these to be under budget for 2014. The Lisgar TL upgrade payment was delayed into 2015, only the study agreement payment was completed in 2014. The original schedule from Hydro One was to complete Orleans TS in 2014 and this has now been updated to spring 2015, which has delayed the final milestone payment until that time. A true-up payment was required for the Hawthorne TS and Cyrville TS CCRAs. The Hawthorne agreement was signed in 2004 and included the addition of new 115kV breaker positions and about 3km of new transmission lines. Under the agreement it was expected a load growth of 2-3% over the first 15 years of the contract. This has resulted in $3M in short fall for the past five years of both the Hawthorne and Cyrville agreements. In addition to this we have estimated that we will be a $10M future liability exists on the remainder of the agreements.

Facilities Implementation Plan

The expenditures related to the purchase of two parcels of land upon which HOL will construct its new Eastern Operations & Campus and its Southern Operations centre and warehouse facilities. An amount for the purchase of land for the construction of new facilities was included in HOL's 2012 rate base used to calculate distribution rates resulting from its last cost of service rate case (EB-2011-0054). Details of the spending are outlined in Table 3.4.10.

Table 3.4.10 - Facilities Implementation Plan Historic Spend

Facility		$'000				
		2011	2012	2013	2014 ~~Q2*~~	2015
		Act.	Act.	Act.	Act.	Plan
East Ops & Campus	Land	-	250	10,002	~~21~~	-
	Building	234	492	287	~~432~~ 467	3,835
South Ops	Land	-	6,704	2,537	-	-
	Building	68	140	83	-	1,098
Total		302	7,586	12,909	~~453~~ 467	4,933

The 2011-2014 budget to actual variances are the result of delays in the schedule for the purchase of land and construction of Hydro Ottawa's new facilities. More specifically, the 2011 variance is the result of underspending on the services provided by Hydro Ottawa's real estate advisors. Spending in 2012 and 2013 was significantly lower than forecasted due to delays in the project. Actual spend reflects the purchase of the two land parcels whereas the budget had also set aside monies for the construction of the facilities.

3.4.5.2 Forecast Trend

Table 3.4.11 - General Plant Forecasted Spend

Investment Category / Capital Program	Forecast (Planned) $'000				
	2016	2017	2018	2019	2020
General Plant	**45,899**	**48,138**	**18,276**	**18,695**	**13,954**
Buildings - Facilities	688	509	408	323	243
Customer Service	3,740	2,361	1,148	6,658	1,139
ERP System	5,043	354	350	354	1,061
Fleet Replacement	1,455	1,209	1,452	1,480	1,876
IT New Initiatives	2,127	1,166	1,006	1,218	1,203

IT Life Cycle & Ongoing Enhancement	1,424	1,737	1,905	2,232	1,816
Operations Initiatives	1,074	452	405	892	1,069
Tools Replacement	512	521	530	539	548
Hydro One Payments	4,575	5,000	5,000	5,000	5,000
Facilities Implementation Plan	25,262	34,829	6,073	-	-

Over the period 2016-2020 Hydro Ottawa General Plant investments will be addressing Operational Effectiveness and Customer Value. Life cycle investments remain flat while there are increases in spending in the Customer Service Capital Program in 2019, details of this change is outlined in the Materials Investments section 3.6.

The forecasted trend for Hydro One Payments is expected to remain consistent over the next 5 years. This will represent an increase from the $3M average from 2012 through 2015 due to the increased amount of work associated and existing agreements. The actual expenditures forecasted are expected to change as agreements with HONI are finalized, and therefore it remains difficult to determine the expected costs for new projects or true-up payments.

New agreements are expected to be signed for a number of transmission connected stations and jointly owned HOL/Hydro One stations through 2020. Below is a list of projects that have been identified to start by the end of 2016 that will have new agreements with Hydro One issued. These projects may or may not require a capital contribution by HOL, and this will only be known once Hydro One completes the evaluation of the projects and a contract is signed, timelines of which have not yet been determined.

- Merivale DS Rebuild;
- Woodroffe TW 13kV Switchgear Replacement ;
- Overbrook TO Switchgear Replacement;
- New South 28kV Substation;
- Lisgar TL transformer Upgrade;
- Richmond South DS Rebuild; and
- 2nd 230kV Supply to Terry fox MTS

There has been an increase in the number of agreements signed with Hydro One over the last five years and as a result HOL has obligations under these agreements to complete true-up reviews on five year increments. These reviews may require that payments be made for any short fall of revenue generated by Hydro One as a result of the forecasted load from HOL not materializing. While HOL does attempt to maintain the loading committed to in the CCRA agreements, shortfalls do occur. Table 3.1.11 outlines the existing CCRA contracts that have true-up reviews over the 2016-2020 timeframe.

Table 3.4.12 - Hydro One CCRA True-up Dates

Station	2016	2017	2018	2019	2020
Hawthorne 115kV Lines Upgrade					X
Cyrville MTS				X	
Ellwood MTS					X
Terry Fox MTS			X		
Orleans TS					X
Hawthorne TS					X
Overbrooke TS	X				
Limebank MS					X

Spending in the Facilities Implementation Plan is set to be completed by 2018. Table 3.4.13 below sets out HOL's forecasted expenditure for its new Eastern Operations & Campus and its Southern operation/warehouse centre facilities. The capital expenditure for the construction of the new facilities is a once in a generation investment. This investment was identified almost fifteen years ago at amalgamation as necessary to consolidate administrative functions; to better locate the operation centres; to modernize the work environment and to provide for future growth. HOL's existing facilities are between 45 and 60 years old and were designed and built in an era and are now beyond their end of life. These costs can be broken down by the two proposed projects.

Table 3.4.13 - Facilities Implementation Plan Forecasted Spend

Facility		Forecast (Planned) $'000				
		2016	2017	2018	2019	2020
East Ops & Campus	Land	-	-	-	-	-
	Building	19,642	25,818	6,073	-	-
South Ops	Land	-	-	-	-	-
	Building	5,620	9,011	-	-	-
Total		25,262	34,829	6,073	-	-

3.4.5.3 Y Factor Treatment

HOL proposes to recover the costs associated with the construction of new head office and operations buildings via a Y factor. Y factors are mechanisms available under incentive regulation to accommodate revenue requirement pass throughs. HOL proposes to use a Y factor to pass along the costs associated with the construction of the administrative and operational buildings to ratepayers in the years that said costs are incurred. HOL proposes to use the Y factor rather than embed the full costs into revenue requirement because HOL does not know at this point in time a) the precise amount of costs that is to be recovered; b) when (ie. the year) said costs will be incurred and hence recoverable. HOL proposes to record the expenses incurred with the construction of its new facilities in a Y Factor Account.

3.4.5.4 Proceeds of Sale of Existing Facilities

Following the move to its new facilities, HOL's existing Albion Street, Merivale Road and Bank Street facilities will be marketed for sale. At this time, HOL does not know the final sale price for the land and buildings at each location nor the year in which the sale will occur.

HOL proposes to credit ratepayers with the entire value of the after tax proceeds of sale for the buildings and for 50% of the after tax proceeds for the sale of the lands. The 50% share of the after tax proceeds for the sale of the lands recognizes that land is an undepreciated asset. HOL is proposing to establish a deferral account to record the after tax proceeds from the sale of the buildings and lands and will bring forward the deferral account for clearance in a future proceeding once the buildings and lands have been sold.

3.5 Justifying Capital Expenditures

The following section provides the data, information and analysis to support the forecasted capital expenditures as proposed by HOL.

3.5.1 Overall Plan

The Overall Plan section provides comparative data from the historic period of 2011-2015 and the forecast period of 2016-2020 by Investment Category and by primary driver.

3.5.1.1 Historic Expenditures by Category

Table 3.5.1 and Figure 3.5.1 depict the expenditures by investment category over the historic period of 2011-2015 and the projected expenditures for the forecast period of 2016-2020.

Table 3.5.1 - Expenditures by Investment Category in $'000

Investment Category	$'000											
	Historical						Forecast					
	2011	2012	2013	2014~~*~~	*2015	Avg.	2016	2017	2018	2019	2020	Avg.
System Access	31,635	30,868	37,675	~~39,010~~ 35,542	35,275	~~34,892~~ 34,199	36,263	35,156	35,132	35,835	36,551	35,787
System Renewal	27,778	29,628	29,540	~~36,997~~ 37,408	40,048	~~32,798~~ 32,880	41,033	31,823	36,491	35,980	35,718	36,209
System Service	26,716	21,362	23,937	~~21,753~~ 19,298	20,806	~~22,915~~ 22,424	22,235	33,957	29,518	30,473	33,314	29,899
General Plant	10,215	27,191	40,484	~~18,743~~ 32,754	20,850	~~23,497~~ 26,299	45,899	48,138	18,276	18,695	13,954	28,992
Grand Total	**96,343**	**109,049**	**131,635**	**~~116,503~~ 125,002**	**116,979**	**~~114,102~~ 115,802**	**145,430**	**149,073**	**119,418**	**120,982**	**119,538**	**130,888**

Note: ~~*2014 actuals are based on the Q2 forecast~~ *2015 based on budget

Figure 3.5.1 - Expenditures by Investment Category

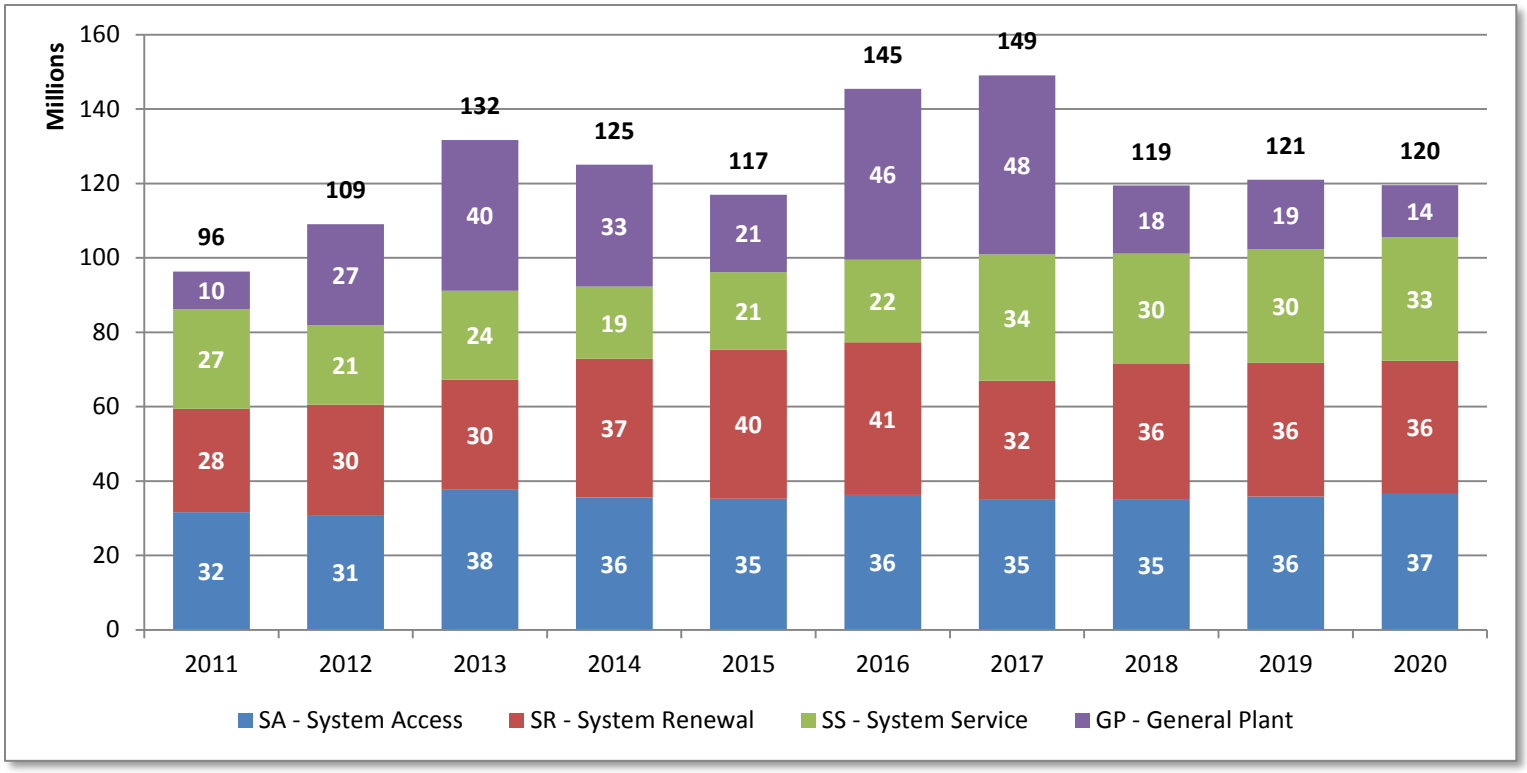
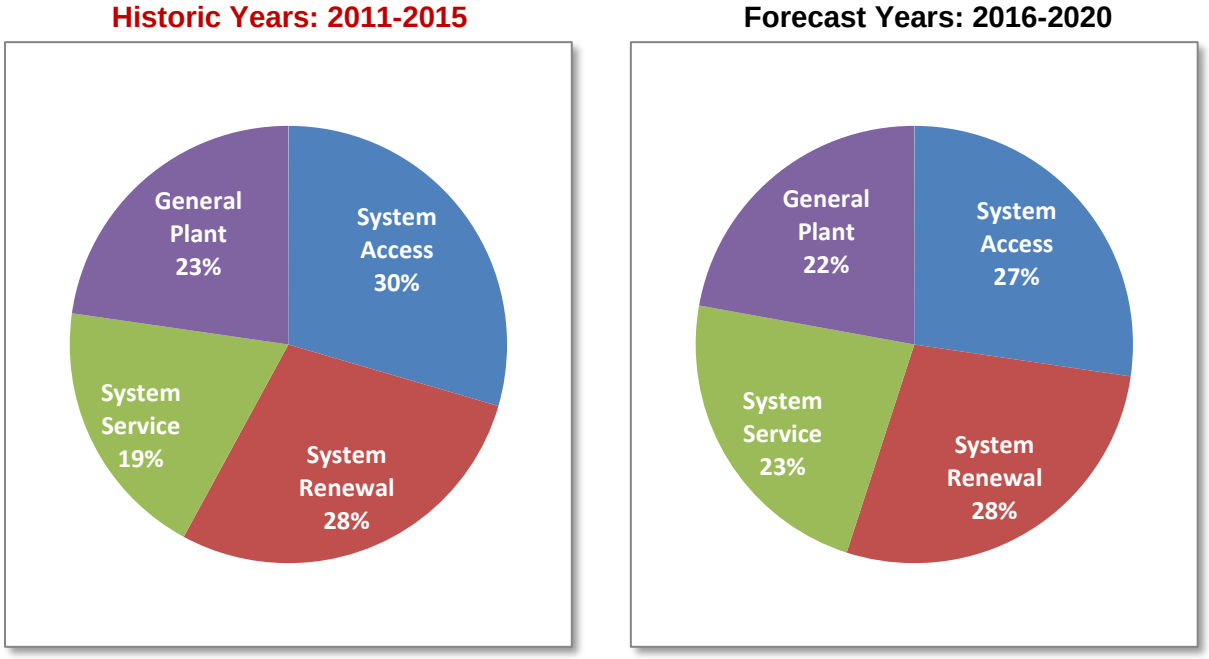


Figure 3.5.2 shows the average percent contribution of annual expenditure to each of the Investment Categories over the historic period of 2011-2015 compared to the forecast period of 2016-2020.

Figure 3.5.2 - Average Expenditure Distribution by Investment Category



3.5.1.2 Impact on O&M Costs

Impacts to operation and maintenance costs vary by Investment Category, as described below.

System Access

System Access projects can introduce new assets to the system resulting in an increase of equipment requiring maintenance, and additional potential failure points within the grid. These projects can also involve expanding the communication infrastructure, and as a result could incur ongoing licencing fees.

System Service

System Service investments represent the costs associated with growing the distribution system, thereby increasing the number of assets to maintain and introducing additional potential failure points within the system. These projects can also involve expanding the communication infrastructure, and as a result could incur ongoing licencing fees.

System Renewal

System Renewal Investments target the replacement of ageing infrastructure. As an asset ages, the costs associated with maintenance increases as the activities become more onerous. When an asset is replaced, maintenance is still required, but typically involves less time and resources, resulting in lower O&M expenses in comparison. As well, as an asset ages and its condition deteriorates to the point of failure, there are resulting O&M costs associated with the emergency work required to respond and restore power. Through pro-active replacement, these additional costs can be avoided.

As HOL replaces assets, new technologies are introduced. There are benefits to such improvements, such as reduced crew travel time, but other costs such as communication licencing, software licencing, increased communication infrastructure and a need for device specific training can increase O&M costs.

3.5.1.3 Drivers by Investment Categories

The drivers by investment category are expected to remain constant from the historic period moving through the forecast period and have been summarized in Table 3.5.2. For the definitions of the drivers refer to Section 2.1.1 Asset Management Objectives.

Table 3.5.2 - Drivers by Investment Category

Investment Category	Driver(s)
System Access	• 3rd Party Requirements • Customer Service Request • Mandated Service Obligation
System Renewal	• Assets at end of Service Life o Failure Risk o Failure o High Performance Risk o Substandard Performance
System Service	• Capacity Constraint • Reliability • System Efficiency
General Plant	• System Capital Investment Support • System Maintenance Support • Business Operations Efficiency • Non-System Physical Plant

Table 3.5.3 shows the forecasted expenditures by driver and Figure 3.5.3 shows the distribution by driver of the total expenditures over the forecast period.

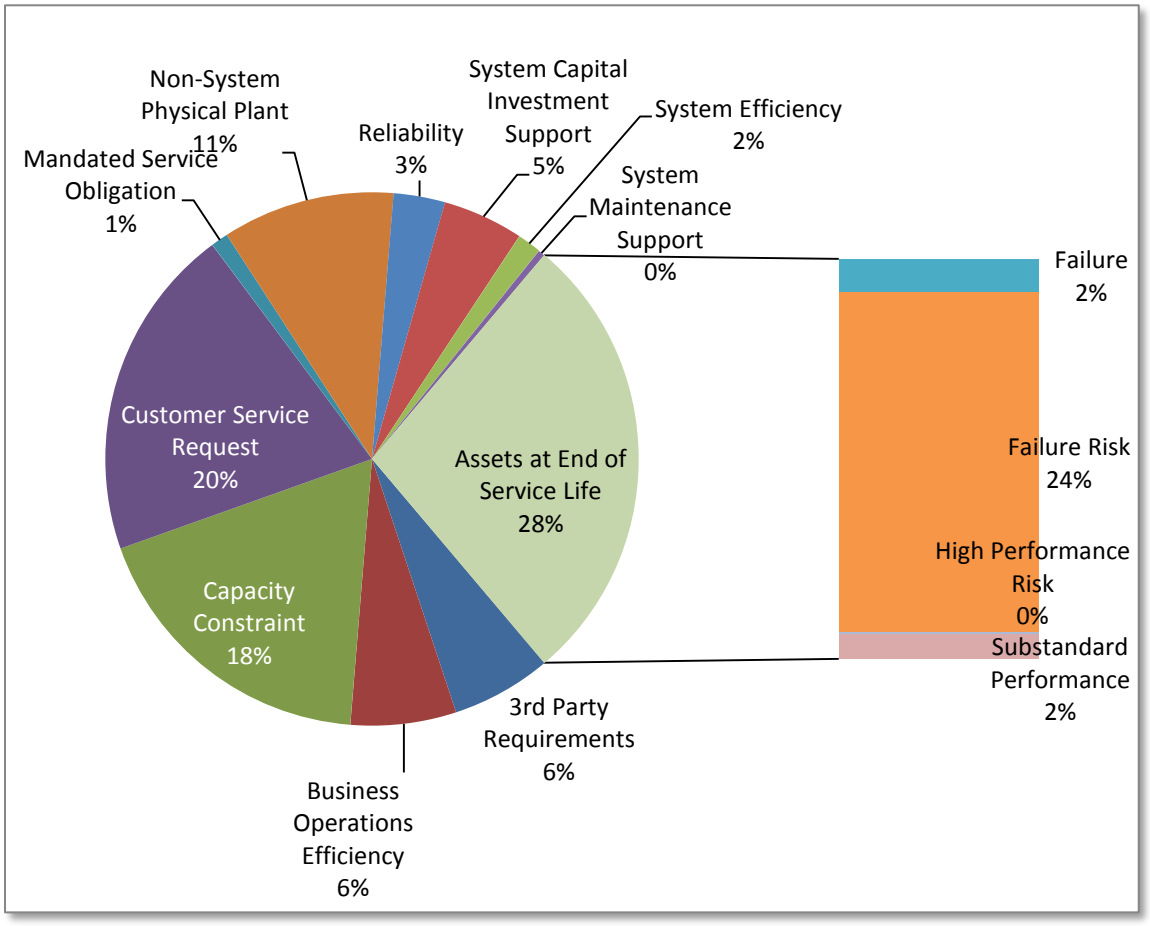
1

Table 3.5.3 - Forecasted Expenditures by Driver

Investment Category	Driver	$'000									
		2011A	2012A	2013A	2104A	2015	2016	2017	2018	2019	2020
System Access	3rd Party Requirements	~~6,542~~ 7,743	~~14,998~~ 5,942	~~17,242~~ 10,005	~~13,583~~ 9,208	~~10,833~~ 7,814	7,620	7,773	7,928	8,087	8,248
	Customer Service Request	~~767~~ 22,207	~~380~~ 23,038	~~380~~ 25,668	~~426~~ 25,279	~~688~~ 26,178	27,328	26,042	25,836	26,352	26,880
	Mandated Service Obligation	~~2,024~~ 1,684	~~3,658~~ 1,895	~~9,414~~ 2,008	~~3,894~~ 1,055	~~3,885~~ 1,283	1,315	1,341	1,368	1,395	1,423
System Renewal	Failure	~~580~~ 6,146	~~568~~ 5,186	~~539~~ 5,322	~~386~~ 6,814	~~512~~ 2,991	3,000	3,000	3,000	3,000	3,000
	Failure Risk	~~302~~ 16,648	~~7,586~~ 22,078	~~12,909~~ 22,494	~~453~~ 28,830	~~4,933~~ 35,169	36,732	26,284	30,763	30,321	29,975
	High Performance Risk	~~7,743~~ 403	~~5,942~~ 150	~~10,005~~ 303	~~9,437~~ 387	~~7,814~~ 319	-	168	194	176	183
	Substandard Performance	~~22,207~~ 3,066	~~23,031~~ 2,214	~~25,661~~ 1,421	~~28,410~~ 1,376	~~26,178~~ 1,519	1,301	2,370	2,534	2,483	2,560
System Service	Capacity Constraint	~~1,684~~ 24,496	~~1,895~~ 19,074	~~2,008~~ 22,429	~~1,163~~ 17,619	~~1,283~~ 16,004	15,955	26,416	23,325	26,082	27,778
	Reliability	~~6,146~~ 856	~~5,186~~ 1,010	~~5,322~~ 394	~~6,493~~ 969	~~2,991~~ 3,305	4,282	5,164	4,061	2,913	3,995
	System Efficiency	~~16,648~~ 1,363	~~22,078~~ 1,272	~~22,494~~ 1,105	~~28,889~~ 707	~~35,219~~ 1,379	1,998	2,377	2,133	1,478	1,541

General Plant	Business Operations Efficiency	~~403~~ 6,542	~~150~~ 14,998	~~303~~ 17,242	~~326~~ 12,473	~~319~~ 10,833	13,407	6,070	4,814	11,352	6,288
	Non-System Physical Plant	~~3,066~~ 1,069	~~2,214~~ 7,967	~~1,421~~ 13,289	~~1,514~~ 1,002	~~1,519~~ 5,621	688	509	408	323	243
	System Capital Investment Support	~~24,496~~ 2,024	~~19,081~~ 3,658	~~22,436~~ 9,414	~~20,018~~ 18,960	~~16,004~~ 3,885	6,030	6,209	6,452	6,480	6,876
	System Maintenance Support	~~856~~ 580	~~1,010~~ 568	~~394~~ 539	~~921~~ 319	~~3,305~~ 512	512	521	530	539	548
Total		**~~94,829~~**	**~~109,050~~**	**~~131,635~~**	**~~116,727~~**	**~~116,979~~**	**145,430**	**149,073**	**119,418**	**120,982**	**119,538**

Figure 3.5.3 - Contribution to Total Forecasted (2016-2020) Expenditures by Driver



3.5.1.4 System Capability Assessment

Over the period 2016-2020 HOL will be addressing three stations that currently have restrictions for the connection of REG within the capital expenditures: Lisgar TL by contributing to the transformer upgrade being completed by HONI, Hinchey TH by contributing to the transformer upgrade being completed by HONI, and Leitrim MS by adding a second transformer at the station. Further details of the system capability assessment for REG connections can be found in section 3.3. As well, whenever station transformers are identified for replacement through the Asset Management Process (2 Asset Management Process) due to either reaching their end of life or capacity constraints, the new units will have reverse flow capabilities specified to eliminate the potential restriction to the connection of REG.

3.5.2 Material Investments

This section describes HOL's Budget Programs and projects specifically those that meet the materiality threshold of $750k in each of the four investment categories (System Access, System Renewal, System Service, and General Plant) for the forecast years of 2016 through 2020.

3.5.2.1 System Access

System Access investments are "modifications (including asset relocation) to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generation customer) or group of customers with access to electricity services via the distribution system" as *per Section 5.1.1* of Chapter 5.Table 3.5.4 details HOL's full expenditures by Capital Program within System Access from 2016 through 2020.

Table 3.5.4 - System Access Forecast Expenditure by Capital Program

Capital Program	Budget Program	$'000				
		2016	2017	2018	2019	2020
Plant Relocation	Plant Relocation & Upgrade	7,620	7,773	7,928	8,087	8,248
Residential	Residential Subdivision	6,889	7,027	7,167	7,311	7,457
Commercial	New Commercial Development	13,423	13,042	12,576	12,827	13,084
System Expansion	System Expansion Demand	3,479	2,366	2,413	2,462	2,511
Stations Embedded Generation	Embedded Generation	377	384	392	400	408
Infill & Upgrade	Infill Service (Res & Small Com)	3,160	3,223	3,288	3,353	3,420
Damage To Plant	Damage to Plant	1,148	1,171	1,195	1,219	1,243
Metering	Suite Metering	167	170	173	177	180
Total		**36,263**	**35,156**	**35,132**	**35,835**	**36,551**

3.5.2.1.1 Plant Relocation

The HOL Plant Relocation Capital program is in response to the Ontario Energy Board's *Distribution System Code (August 21, 2014)* (DSC), *section 3.4 – Relocation of Plant*, *3.4.1*, which states that "When requested to relocate distribution plant, a distributor shall exercise its rights and discharge its obligations in accordance with existing legislation such as the *Public Service Works on Highways Act*, regulations, formal agreements, easements and common law.

In the absence of existing arrangements, a distributor is not obligated to relocate the plant. However, the distributor shall resolve the issue in a fair and reasonable manner. Resolution in a fair and reasonable manner shall include a response to the requesting party that explains the feasibility or infeasibility of the relocation and a fair and reasonable charge for relocation based on cost recovery principles."

3.5.2.1.2 Residential, Commercial, System Expansion and Infill & Upgrade

HOL's Residential, Commercial, System Expansion, and Infill & Upgrade Capital Programs are driven by the requirements as set out in the DSC, s*ection 6 – Distributors' Responsibilities, 6.1 – Responsibilities to Load Customers, 6.1.1,* which states that "A distributor shall make every reasonable effort to respond promptly to a customer's request for connection. In any event a distributor shall respond to a customer's written request for a customer connection within 15 calendar days. A distributor shall make an offer to connect within 60 calendar days of receipt of the written request, unless other necessary information is required from the load customer before the offer can be made".

3.5.2.1.3 Stations Embedded Generation

The HOL Stations Embedded Generation Capital Program is driven by the DSC requirement from s*ection 6.2 – Responsibilities to Generators, 6.2.4* that states "Subject to all applicable laws, a distributor shall make all reasonable efforts in accordance with the provisions of section 6.2 to promptly connect to its distribution system a generation facility which is subject of an application for connection".

3.5.2.1.4 Damage to Plant

HOL's Damage to Plant Capital Program covers costs associated with damage to HOL owned plant which is caused by a third party. HOL targets 100% recovery of the costs from the third party; however, where tracking information is not available, HOL absorbs the cost or may attempt at recovery from the insurer.

3.5.2.1.5 Metering

The HOL Metering Capital Program is driven by the DSC requirement from s*ection 5.1 – Provision of Meters and Metering Services, 5.1.1* that states "A distributor shall provide, install

and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distributor's distribution system…".

HOL forecasts expenditures within System Access using a number of factors:

- Analysis of historic trends;
- Forecasted economic and population statistics;
- Known developments; and
- City of Ottawa plans;

Details from City of Ottawa plans used in the forecasting of expenditures are explained below.

City of Ottawa Official Plan

All information within this section has been obtained from the City of Ottawa Official Plan, Section2 – Strategic Directions, Figure 2.2.

Table 3.5.5 - Project Growth in Population, Households & Employment, City of Ottawa, 2006 to 2031

Population				
Area	**2006**	**2011**	**2021**	**2031**
Inside the Greenbelt	533,000	540,000	562,000	591,000
Outside Greenbelt, Urban	252,000	291,000	367,000	432,000
Rural	86,000	91,000	102,000	113,000
Total	**871,000**	**923,000**	**1,031,000**	**1,136,000**

Households				
Area	**2006**	**2011**	**2021**	**2031**
Inside the Greenbelt	228,000	237,000	258,000	278,000
Outside Greenbelt, Urban	88,000	106,000	140,000	168,000
Rural	30,000	32,000	38,000	43,000
Total	**346,000**	**376,000**	**436,000**	**489,000**

Employment				
Area	**2006**	**2011**	**2021**	**2031**
Inside the Greenbelt	432,000	457,000	482,000	506,000
Outside Greenbelt,	72,000	95,000	128,000	162,000

Urban				
Rural	25,000	26,000	30,000	35,000
Total	**530,000**	**578,000**	**640,000**	**703,000**

Table 3.5.5 shows that growth within the City of Ottawa is expected to continue into the future and that the total average annual growth rates from 2011 to 2021 are:

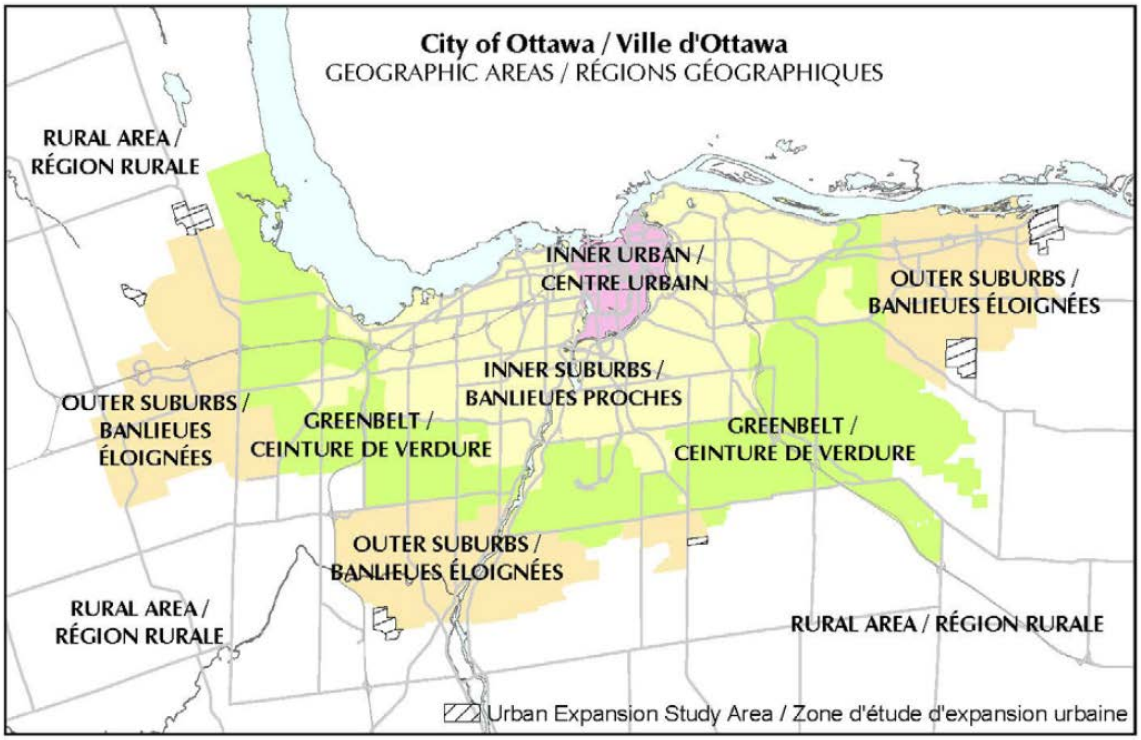
- Population – 1.11%
- Households – 1.49%
- Employment – 1.02%

Therefore, HOL expects the continuing trend of requests for connection of residential subdivisions and the associated mixed-use centres, along with employment centres.

City of Ottawa Transportation Master Plan

The City of Ottawa's Transportation Master Plan identifies the transportation facilities and services that are required to meet the needs of the growing City. HOL utilizes this information to help forecast customer connection requests and to plan the sustainment of the distribution system. The following figure and table depict the increasing requirements by region, within the City of Ottawa out to 2031.

Figure 3.5.4 - Location of Inner Area, Inner Suburbs & Outer Suburbs - City of Ottawa



**Source: City of Ottawa Transportation Master Plan, 2013 – Exhibit 2.1*

Table 3.5.6 - Population & Employment: 2011 Actual & 2031 Projections

Area	Population			Employment		
	2011	2031	Growth and distribution	2011	2031	Growth & distribution
Inner Area	97,200	116,400	19,200 (9%)	170,600	201,800	31,200 (23%)
Inner Suburbs	432,500	459,300	26,800 (13%)	287,400	355,300	67,900 (49%)
Kanata/ Stittsville	105,200	162,000	56,800 (27%)	51,300	62,500	11,200 (8%)
Barrhaven	71,200	107,400	36,200 (17%)	11,100	21,800	10,700 (8%)
Riverside South/Leitrim	15,900	35,800	19,900 (9%)	4,000	7,800	3,800 (3%)
Orléans	108,200	143,400	35,200 (16%)	20,600	33,000	12,400 (9%)
Rural Ottawa	91,400	111,700	20,300 (9%)	20,000	20,900	900 (1%)
Total	***922,000***	***1,135,900***	***213,900 (100%)***	***564,900***	***703,200***	***138,100 (100%)***

**Source: City of Ottawa Transportation Master Plan, 2013 – Exhibit 2.10*

Within the Transportation Master Plan, the City of Ottawa has developed an "Affordable Road Network" planned out to 2031. This "Affordable Road Network" is the prioritized City projects based on the expected funding levels, and as such, is the most reasonable list of projects to base future road work projections which is used to forecast Plant Relocation spending levels.

The "Affordable Road Network" projects have been broken out by phases, and are listed in Table 3.5.7, showing only those projects planned until 2025, and graphically in Figure 3.5.5.

Table 3.5.7 - City of Ottawa Affordable Road Network - Projects by Phase

Currently Under Construction		
Sector	**Project**	**Description**
Southeast	Alta Vista Transportation Corridor	New two-lane road between Riverside Drive and the Ottawa Hospital
Southwest	Greenbank Road	Widening from two to four lanes between Malvern Drive and Strandherd Drive
Southeast	Hunt Club Road Extension	Eastward extension of Hunt Club road to Highway 417
East	St. Joseph Boulevard	Widening from two to four lanes between Old Tenth Line Road and Trim Road
Southwest	Strandherd-Earl Armstrong Bridge	New bridge crossing between Strandherd Drive and Earl Armstrong Road
East	Trim Road	Widening from two to four lanes between North Service Road and Innes Road

Phase 1: 2014-2019		
Sector	**Project**	**Description**
Southeast	Airport Parkway (1)	Widen from two to four lanes between Brookfield Road and Hunt Club Road
East	Blackburn Hamlet Bypass Extension (1)	New four-lane road between Orléans Boulevard and Navan Road
East	Brian Coburn Boulevard Extension	New two-lane road (ultimately four-lane) between Navan Road and Mer Bleue Road
West	Campeau Drive	New four-lane road between Didsbury Road and Huntmar Drive
Rural	Country Club Road	New two-lane road between eastern terminus of Golf Club Way and Jenkinson Road
West	Earl Grey Drive Underpass	New underpass of Terry Fox Drive
Southwest	Greenbank Road Extension	New four-lane road between Cambrian Road and Jockvale Road
West	Old Richmond/West Hunt Club	Widen Old Richmond Road/ West Hunt Club Road from two to four lanes between Hope Side and Highway 416
West	Stittsville North-South Arterial (1)	New two-lane road between Fernbank Road and Abbott Street
West	Klondike Road	Urbanize existing two-lane rural cross section between March Road and Sandhill Road
East	Mer Bleue Road	Widen from two to four lanes between Brian Coburn Boulevard and Renaud Road
West	Palladium Drive Realignment	Realign in vicinity of Huntmar Road to new north-south arterial
Southwest	Strandherd Drive (1)	Widen from two to four lanes between Fallowfield Road and Maravista Drive

Phase 2: 2020-2025		
Sector	**Project**	**Description**
Southeast	Bank Street	Widen from two to four lanes between Earl Armstrong Road extension and south of Leitrim
East	Blackburn Hamlet Bypass Extension (2)	New four-lane road between Innes Road and Orléans Boulevard
West	Carp Road	Widen from two to four lanes between Highway 417 and Hazeldean Road
Southwest	Chapman Mills Drive	New four-lane road between Strandherd Drive and Longfields Drive
West	Eagleson Road	Widen from two to four lanes between Cadence Gate and Hope Side Road
Southwest	Jockvale Road	Widen from two to four lanes between Cambrian Road and Prince of Wales Drive
West	Kanata Avenue	Widen from two to four lanes between Highway 417 and Campeau Drive
West	Stittsville North-South Arterial (2)	New four-lane road between Palladium Drive (at Huntmar) and Abbott Street
Southeast	Lester Road	Widen from two to four lanes between Airport Parkway and Bank Street
Southwest	Strandherd Drive (2)	Widen from two to four lanes between Maravista Drive and Jockvale Road
East	Tenth Line Road	Widen from two to four lanes between Harvest Valley Road and Wall Road

**Source City of Ottawa Transportation Master Plan, 2013 – Exhibit 7.2*

City of Ottawa Community Design Plans

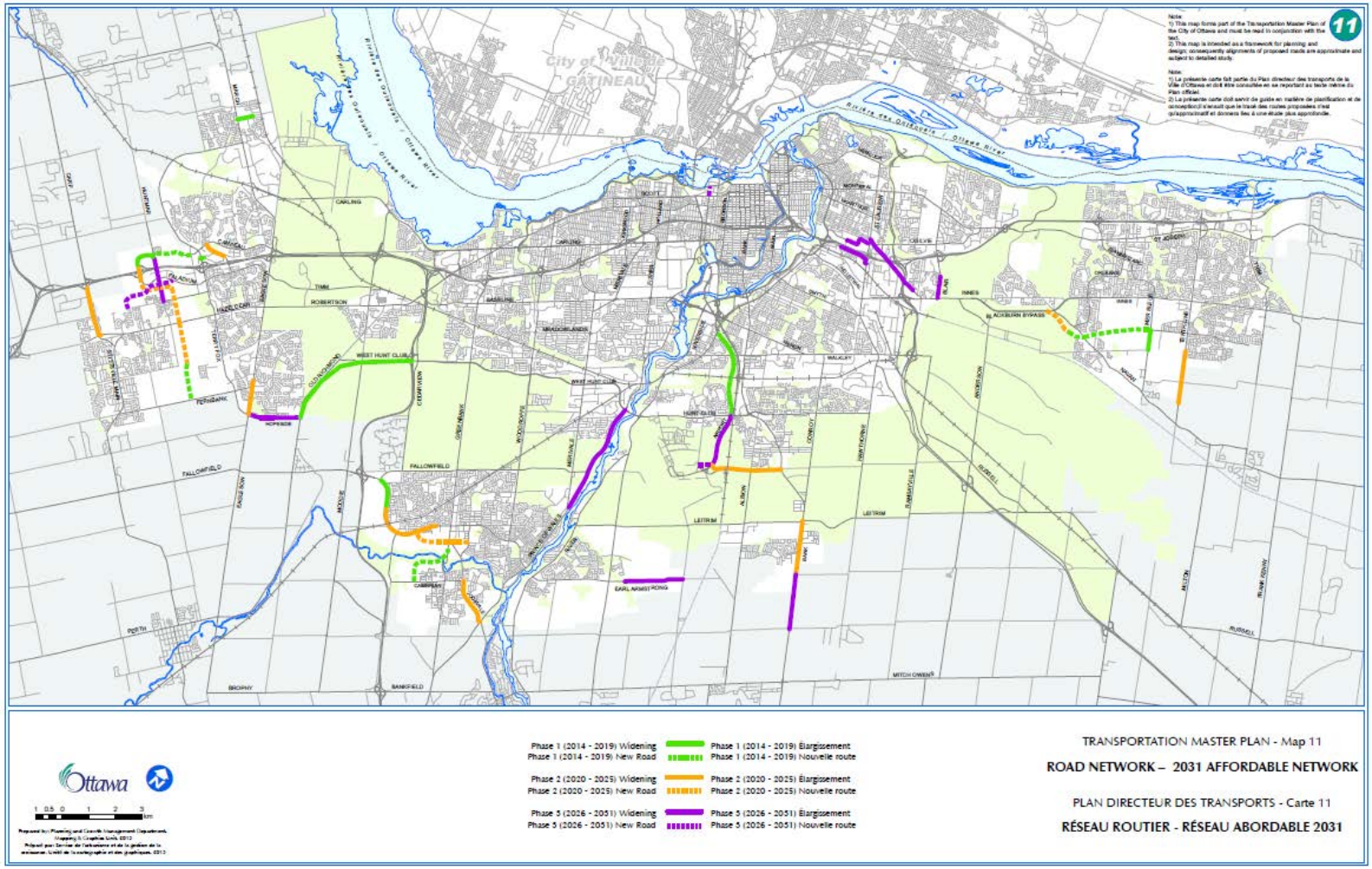
HOL also references published Community Design Plans from the City of Ottawa to forecast future residential and mixed-use centres.

Currently, there are 32 Community Design Plans published on the City of Ottawa's website which describe a mix of development types. A summary of the CDPs can be found in Table 3.5.8 and is based upon information provided within each study. Further details from the City of Ottawa CDPs have been captured in Appendix E.

Table 3.5.8 - City of Ottawa Community Design Plans Summary

Study	Study Area (ha)	GFA (ha)	No. Res. Units	Land Use Type
Barrhaven South CDP	500	188.9	6,862	Mixed-Use
Bank Street CDP	101			Mixed-Use
Bayview Station District CDP	29.5	55		Mixed-Use
Bayview/Somerset Area Secondary Study	89.7		1,590	Mixed-Use
Beechwood CDP	22		819	Mixed-Use
Cardinal Creek Village Concept Plan	208	95	3,500	Mixed-Use
Carp Road Corridor CDP	2475		0	Commercial
Village of Carp CDP	49.5		543	Mixed-Use
Village of Constance Bay Community Plan	114		204	Mixed-Use
Downtown Ottawa Urban Design Strategy				
East Urban Community (Phase 1 Area) CDP	570		3,498	Mixed-Use
East Urban Community (Phase 2 Area) CDP	240		1,726	Mixed-Use
Escarpment Area District Plan				Mixed-Use
Fernbank CDP	674	310	11,000	Mixed-Use
Greely CDP	1276		729	Mixed-Use
Leitrim CDP	500	362.3	5,300	Mixed-Use
Mer Bleue CDP	160	113.7	3,000	Mixed-Use
Kanata West Concept Plan	887		5,000	Mixed-Use
North Gower CDP	278	208	520	Mixed-Use
Old Ottawa East CDP	158		2,250	Mixed-Use
Orleans Industrial Park Study	316	18.7	0	Commercial
Queensway Terrace North	140			
Richmond Road/Westboro CDP	270		3,970	Mixed-Use
Richmond Road/Westboro Transpo Plan				
Riverside South CDP	1800	1450	18,300	Mixed-Use
Scott Street CDP	57.7		1,500	Mixed-Use
South Nepean Town Centre CDP	165	35	11,000	Mixed-Use
St. Joseph Boulevard Corridor Study	67.3			Mixed-Use
Uptown Rideau CDP	21			Mixed-Use
Transit-Oriented Development (TOD) Plans				
Village of Richmond CDP	879			Residential
Wellington Street West CDP	232		950	Mixed-Use

Figure 3.5.5 - City of Ottawa Transportation Master Plan, 2013-2031 Affordable Network



**Source: City of Ottawa Transportation Master Plan – Map 11*

3.5.2.2 System Renewal

System Renewal investments "involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services" as per Section *5.1.1* of Chapter 5.

The following section details HOL's System Renewal Budget Programs and projects from 2016 through 2020 that meet the materiality threshold of $750k. Table 3.5.9 shows the full Budget Program expenditures over the forecast period.

Table 3.5.9 - System Renewal Forecast Expenditure by Program

Capital Program	Budget Program	$'000				
		2016	2017	2018	2019	2020
Stations Asset	Stations Transformer Replacement	10,729	4,620	6,533	8,225	7,965
	Stations Switchgear Replacement	5,424	7,088	7,408	6,871	6,114
	Stations Plant Failure	185	107	107	107	107
Stations Refurbishment	Stations Enhancements	597	634	731	662	691
Distribution Asset	Pole Replacement	8,641	6,592	7,608	6,886	7,189
	Insulator Replacement	-	168	194	176	183
	Elbow & Insert Replacement	289	190	219	198	207
	Dist. Transformer Replacement	804	808	933	844	881
	Civil Rehabilitation	3,153	636	734	664	694
	Cable Replacement	5,974	5,262	6,073	5,496	5,738
	Switchgear New & Rehab	1,222	376	434	393	410
	O/H Equipment New & Rehab	785	902	1,041	942	983
	Plant Failure Capital	2,815	2,893	2,893	2,893	2,893
Metering	Remote Disconnected Smart Meter	415	1,547	1,584	1,623	1,662
Total		**41,033**	**31,823**	**36,491**	**35,980**	**35,718**

3.5.2.2.1 Stations Transformer Replacement

Details on the Stations Transformer Replacement Budget Program can be found in Attachment B-1(A).

3.5.2.2.2 Stations Switchgear Replacement

Details on the Stations Switchgear Replacement Budget Program can be found in Attachment B-1(A).

3.5.2.2.3 Stations Plant Failure

The Station Plant Failure Budget Program is set up to capture costs associated with station assets that have failed or that have substandard performance and are no longer meeting the requirements and require immediate refurbishment to extend the service life or replacement.

3.5.2.2.4 Stations Enhancements

Costs associated with the Stations Enhancement Budget Program cover the replacement of non-distribution equipment such as, building assets, station batteries, and cable racking when they have reached end of functional life. For building assets the costs are associated with sustaining civil, electrical, mechanical, structural and security/life safety assets, such as, work on roof, windows, doors, fencing and security equipment.

3.5.2.2.5 Pole Replacement

Details on the Pole Replacement Budget Program can be found in Attachment B-1(A).

3.5.2.2.6 Insulator Replacement

The Insulator Replacement Budget Program is designed for the replacement of overhead insulators typically when they have been deemed to have a high performance risk, or categorized as having a high probability of failure. Currently, there are four types of insulators that have been identified for proactive replacement:

- "WART" type porcelain post insulators;
- Canadian Porcelain pin type 28/46kV insulators;
- Horizontally installed porcelain pin type insulators; and
- Ohio Brass porcelain insulators on standoff brackets.

3.5.2.2.7 Elbow & Insert Replacement

The Elbow & Insert Replacement Budget Program was initiated for the replacement of 28kV non-vented elbows and inserts on distribution transformers to eliminate the safety hazard associated with switching below 0^{o}C. Annually, a specific neighbourhood, or region, is identified to undergo full replacements, creating great efficiencies for labour utilization and future system operability.

3.5.2.2.8 Distribution Transformer Replacement

Details on the Distribution Transformer Replacement Budget Program can be found in Attachment B-1(A).

3.5.2.2.9 Civil Rehabilitation

Details on the Civil Rehabilitation Budget Program can be found in Attachment B-1(A).

3.5.2.2.10 Cable Replacement

Details on the Cable Replacement Budget Program can be found in Attachment B-1(A).

3.5.2.2.11 Switchgear New & Rehabilitation

Details on the Switchgear New & Rehabilitation Budget Program can be found in Attachment B-1(A).

3.5.2.2.12 Overhead Equipment New & Rehabilitation

Details on the Overhead Equipment New & Rehabilitation Budget Program can be found in Attachment B-1(A).

3.5.2.2.13 Distribution Plant Failure

The Distribution Plant Failure Budget Program is set up to capture costs associated with distribution assets that have failed or that have substandard performance and are no longer meeting the requirements and require immediate refurbishment to extend the service life or replacement.

3.5.2.2.14 Remote Disconnected Smart Meter

Details on the Remote Disconnected Smart Meter Budget Program can be found in Attachment B-1(A).

3.5.2.3 System Service

System Renewal investments are "modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future electricity service requirements" as per Section *5.1.1 Investment Categories* of the *OEB Filing Requirements for Electricity Distribution Rate Applications*, published July 17th, 2013.

The following section details HOL's System Service Budget Programs and projects from 2016 through 2020 that meet the materiality threshold of $750k.Table 3.5.10 shows the full Budget Program expenditures over the forecast period.

Table 3.5.10 - System Service Forecast Expenditure by Budget Program

Capital Program	Budget Program	$'000				
		2016	2017	2018	2019	2020
Stations Capacity	Stations New Capacity	5,676	15,272	10,464	14,441	15,626
Distribution Enhancements	Line Extensions	7,522	6,180	7,132	6,455	6,739
	System Voltage Conversion	2,758	4,964	5,729	5,185	5,413
	System Reliability	329	445	513	464	485
	Dist. Enhancements	682	694	801	725	757
Automation	SCADA Upgrades	1,011	1,011	556	51	51
	SCADA - RTU Additions	169	76	87	79	82
	Distribution Automation	3,953	4,719	3,548	2,449	3,510
	Stations Automation	136	597	689	624	651
Total		22,235	33,957	29,518	30,473	33,314

3.5.2.3.1 Stations New Capacity

The expenditures under the Stations New Capacity Budget Program are identified and prioritized through the Asset Management Process (Section 2.1, and more specifically through the Capacity Planning process). The 20-year outlook for capacity requirements are detailed in 3.1.5.1 Ability to Connect New Load.

3.5.2.3.2 Line Extensions

The expenditures under the Line Extensions Budget Program are identified and prioritized through the Asset Management Process (Section 2.1, and more specifically through the Capacity Planning process). The 20-year outlook for capacity requirements are detailed in 3.1.4.1 Ability to Connect New Load.

3.5.2.3.3 System Voltage Conversion

The expenditures under the System Voltage Conversion Budget Program are identified and prioritized through the Asset Management Process (Section 2.1, and more specifically through the Capacity Planning process). The 20-year outlook for capacity requirements are detailed in 3.1.4.1 Ability to Connect New Load.

3.5.2.3.4 System Reliability

The expenditures under the System Reliability Budget Program are identified and prioritized through the Asset Management Process (Section 2.1, and more specifically through the Reliability Planning process) and include projects identified through evaluation of the Worst Feeders (section 1.3.1.1.3).

3.5.2.3.5 Distribution Enhancements

Distribution Enhancement projects are targeted at making improvements to the existing distribution system in terms of reliability and/or operability and are typically targeted towards areas or equipment that are deemed problematic.

3.5.2.3.6 SCADA Upgrades

The SCADA Upgrades Budget Program covers expenditures related to upgrading and/or renewing SCADA equipment that has reached end of life or has become obsolescent.

3.5.2.3.7 SCADA RTU Additions

The SCADA RTU Budget Program covers expenditures related to upgrading and/or renewing SCADA remote terminal units that have reached end of life or has become obsolescent.

3.5.2.3.8 Distribution Automation

The expenditures under Distribution Automation are aimed at making the distribution system "smarter" and improving reliability and operability through the installation of remotely operable devices and sensors.

3.5.2.3.9 Substation Automation

The expenditures under Substation Automation are aimed at increasing visibility into the distribution system and improving reliability and operability through increasing remote operability and reporting/alarms.

3.5.2.4 General Plant

General Plant investments are "modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities" as per Section *5.1.1* of Chapter 5.

Over the period 2016-2020 HOL's General Plant investments will be addressing Operational effectiveness and Customer value. Life cycle investments remain flat. The major initiatives include:

- Facilities Implementation Plan;
- CC&B Enhancements;
- Outage Communication System;
- JDE Application Upgrade;
- Fleet Replacement;
- Enterprise Architecture Program; and
- Mobile Workforce Management.

Further details of these initiatives can be found in Attachment B-1(A).

Table 3.5.11 - General Plant Expenditures by Capital Program

Capital Program	$'000				
	2016	2017	2018	2019	2020
Hydro One Payments	4,575	5,000	5,000	5,000	5,000
Buildings – Facilities	688	509	408	323	243
Customer Service	3,740	2,361	1,148	6,658	1,139
ERP System	5,043	354	350	354	1,061
Fleet Replacement	1,455	1,209	1,452	1,480	1,876
IT New Initiatives	2,127	1,166	1,006	1,218	1,203
IT Life Cycle & Ongoing Enhancement	1,424	1,737	1,905	2,232	1,816
Operation Initiatives	1,074	452	405	892	1,069
Tools Replacement	512	521	530	539	548
Total	**20,637**	**13,309**	**12,203**	**18,695**	**13,954**

3.6 Material Investments

The details on the Budget Programs and projects that meet the materiality threshold of $750k have been included in a separate document which can be found in Attachment B-1(A).

Appendix A

Integrated Regional Resource Planning – Load Forecast

Medium Planning Forecast

Updated July 31, 2014

Weather Correction Values		2010	2011	2012	2013
Source: Hydro One	Norma	0.944	0.91	0.942	0.930
	Extren	1.001	0.970	0.999	0.987

Latest Forecast

	Reference	Historical (Actuals)							Weather Corrected	Preliminary	Source	10-Day LTRs? (MVA)	10-Day LTRs (MW)	Forecast																				
Group		2006	2007	2008	2009	2010	2011	2012	2012	2013				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Downtown A	CARLING	84	80	78	80	86	79	80	76	80	H1	103	93	80	81	82	83	84	85	86	86	87	88	93	94	95	96	96	97	98	99	99	100
	LINCOLNHTS	45	45	41	42	48	46	45	43	39	H1	79	71	45	45	45	45	45	45	44	44	44	44	49	49	49	49	49	48	48	48	48	48
	WOODROFFE	37	33	32	32	34	36	34	32	32	H1	102	92	33	39	39	40	41	42	42	43	43	44	53	53	54	54	55	55	56	56	56	57
Downtown - A Total		167	159	150	153	168	161	159	150	151			256	159	165	166	168	170	172	173	173	175	176	196	196	198	199	200	200	202	203	203	204
Downtown B	HINCHEY	42	46	43	44	48	46	44	42	47	H1	86	77	44	44	47	50	52	56	58	60	62	64	67	69	71	73	75	77	79	81	83	85
	SLATER	113	110	116	121	113	108	99	93	112	H1	131	118	100	101	102	103	104	105	104	103	103	103	103	102	102	102	101	101	101	101	100	100
	LISGAR	59	64	56	59	66	61	61	58	62	H1	82	74	61	61	74	78	81	85	85	85	86	86	87	87	88	89	90	90	90	90	90	89
	KINGEDWARD	76	79	71	71	85	84	78	74	76	H1	79	71	77	76	77	79	81	83	83	84	84	85	86	86	87	87	86	86	86	85	86	86
Downtown - B Total		290	299	286	294	312	300	283	266	297			340	282	283	301	309	318	329	330	331	336	339	343	344	348	350	352	353	356	357	359	360
Downtown C	RUSSELL TS	61	60	58	73	79	82	61	58	68	H1	77	69	61	61	61	63	65	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
	OVERBROOK	77	74	74	76	80	75	78	74	77	H1	144	130	80	81	85	87	89	95	97	98	103	104	105	105	106	107	107	108	109	109	110	110
	ALBION	108	100	95	100	109	104	99	93	67	H1	98	88	71	71	72	72	73	73	73	73	74	74	74	74	75	75	75	76	76	76	77	77
	ELLWOOD	0	0	0	0	0	0	0	0	32	H.O.	65	59	27	27	27	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
	RIVERDALE	84	83	77	68	73	70	92	87	84	H1	117	105	94	97	99	102	105	117	118	119	121	122	124	124	125	126	126	127	128	128	129	129
Downtown - C Total		331	317	304	317	342	331	330	311	328			451	334	337	344	352	361	387	388	389	397	401	404	404	407	409	410	411	414	416	417	418
Downtown TOTAL		788	775	741	764	822	792	772	727	777				774	785	811	829	849	888	891	894	907	916	942	945	953	958	963	965	971	976	980	982

Latest Forecast with consideration of HOL's transfer capability

	Reference	Historical (Actuals)							Weather Corrected	Preliminary	Source	10-Day LTRs? (MVA)	10-Day LTRs (MW)	Forecast																				
Group		2006	2007	2008	2009	2010	2011	2012	2012	2013				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Downtown A	CARLING	84	80	78	80	86	79	80	76	80	H1	103	93	80	81	82	83	84	85	86	86	87	88	93	94	95	96	96	97	98	99	99	100
	LINCOLNHTS	45	45	41	42	48	46	45	43	39	H1	79	71	45	45	45	45	45	45	44	44	44	44	49	49	49	49	49	48	48	48	48	48
	WOODROFFE	37	33	32	32	34	36	34	32	32	H1	102	92	33	39	39	40	41	42	42	43	43	44	53	53	54	54	55	55	56	56	56	57
Downtown - A Total		167	159	150	153	168	161	159	150	151			256	159	165	166	168	170	172	173	173	175	176	196	196	198	199	200	200	202	203	203	204
Downtown B	HINCHEY	42	46	43	44	48	46	44	42	47	H1	86	77	44	44	58	60	62	66	68	70	72	75	67	69	71	73	75	77	79	81	83	85
	SLATER	113	110	116	121	113	108	99	93	112	H1	131	118	100	105	106	113	114	116	115	114	114	113	113	112	112	112	112	111	111	111	110	110
	LISGAR	59	64	56	59	66	61	61	58	62	H1	120	108	61	61	64	67	71	74	74	75	75	76	87	87	88	89	90	90	90	90	90	89
	KINGEDWARD	76	79	71	71	85	84	78	74	76	H1	79	71	77	69	70	67	69	75	75	75	76	76	77	77	78	78	77	77	77	77	78	77
Downtown - B Total		290	299	286	294	312	300	283	266	297			374	282	280	298	307	316	330	332	333	337	340	344	346	350	352	354	355	357	359	361	361
Downtown C	RUSSELL TS	61	60	58	73	79	82	61	58	68	H1	77	69	61	61	61	63	65	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
	OVERBROOK	77	74	74	76	80	75	78	74	77	H1	144	130	80	81	85	91	94	100	101	102	108	109	110	110	111	111	112	113	113	114	114	115
	ALBION	108	100	95	100	109	104	99	93	67	H1	98	88	71	71	72	72	73	73	73	73	74	74	74	74	75	75	75	76	76	76	77	77
	ELLWOOD	0	0	0	0	0	0	0	0	32	H.O.	65	59	27	27	27	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
	RIVERDALE	84	83	77	68	73	70	92	87	84	H1	117	105	94	100	102	99	102	111	112	112	114	116	118	118	119	120	120	120	121	122	123	123
Downtown - C Total		331	317	304	317	342	331	330	311	328			451	334	340	347	353	362	385	387	388	396	400	403	403	406	408	409	410	412	414	416	417
Downtown TOTAL		788	775	741	764	822	792	772	727	777				774	785	811	829	849	888	891	894	907	916	942	945	953	958	963	965	971	976	980	982

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Group	Reference	Historical (Actuals)							Weather Corrected	Preliminary	Source	10-Day LTRs? (MVA)	10-Day LTRs (MW?)	Forecast																		
		2006	2007	2008	2009	2010	2011	2012	2012	2013				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Ottawa - East	MOULTON	42	40	39	39	36	34	31	29	23	H.O.	33+33	34	31	31	31	32	32	32	32	32	32	32	33	33	33	33	33	33	33	33	34	34
	CYRVILLE	0	0	0	0	6	17	21	19	19	H.O.	65	59	27	24	24	30	35	35	37	38	40	41	42	42	44	44	44	44	44	44	44	44
	BILBERYCREEK - H.O.	63	61	56	56	64	54	53	50	55	H1	94	85	53	53	53	54	54	54	54	54	54	54	54	54	55	55	55	55	55	55	55	55
	BILBERYCREEK - H1	34	35	22	24	39	26	26	25	28	H1	94	85	30	31	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	ORLEANS	0	0	0	0	0	0	0	0	0	H1	113	102	0	5	86	90	92	92	94	96	96	98	99	100	100	102	103	105	105	107	107	109
Ottawa - East Total		140	135	117	119	145	132	131	124	124			279	141	144	195	205	212	214	217	219	222	225	228	229	232	233	234	236	237	240	240	242

Group	Reference	Historical (Actuals)							Weather Corrected	Preliminary	Source	10-Day LTRs? (MVA)	10-Day LTRs (MW?)	Forecast																			
		2006	2007	2008	2009	2010	2011	2012	2012	2013				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kanata	MARCHWOOD	34	36	21	36	27	46	42	40	40	H.O.	33+33	34	34	33	34	34	34	35	34	34	34	34	35	35	34	35	35	34	35	35	35	35
	KANATA	58	54	62	54	73	49	50	47	55	H.O.	61	54	46	47	46	47	47	47	47	46	47	47	47	47	48	47	48	47	48	48	48	48
	BRIDLEWOOD	29	34	33	30	35	39	32	30	26	H.O.	33+8	37	24	22	22	22	23	22	22	22	23	39	39	40	39	39	39	39	39	39	39	39
	TERRY FOX	0	0	0	0	0	0	0	0	0	H.O.	100	90	0	25	39	50	78	83	65	65	64	64	63	64	63	63	62	62	61	61	60	60
Kanata Total		121	124	116	120	135	134	125	118	121			215	104	127	141	153	181	186	169	166	168	184	185	185	185	184	184	183	183	182	182	182

Group	Reference	Historical (Actuals)							Weather Corrected	Preliminary	Source	10-Day LTRs? (MVA)	10-Day LTRs (MW?)	Forecast																			
		2006	2007	2008	2009	2010	2011	2012	2012	2013				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Kanata - South	SOUTHMARCH - H.O.	38	34	33	36	39	34	42	40	39	H1	121	109	43	43	43	43	43	43	42	42	42	27	26	26	26	26	26	26	26	26	26	25
	SOUTHMARCH- H1	59	56	52	56	54	56	61	57	58	H1	121	109	61	68	73	67	72	76	80	84	89	92	96	76	78	78	77	77	78	78	78	78
	RICHMOND	6	3	4	4	4	4	4	4	4	H.O.	6	5	6	8	9	10	11	13	31	34	36	35	36	37	37	37	38	38	39	39	38	38
Kanata - South Total		103	93	88	96	98	95	108	101	102			114	110	119	125	120	126	132	154	160	167	154	159	139	141	141	141	142	143	143	142	141

Group	Reference	Historical (Actuals)							Weather Corrected	Preliminary	Source	10-Day LTRs? (MVA)	10-Day LTRs (MW?)	Forecast																			
		2006	2007	2008	2009	2010	2011	2012	2012	2013				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Nepean South	FALLOWFIELD	27	20	23	21	26	27	30	28	29	H.O.	25+25	26	29	31	36	39	38	41	49	51	54	55	58	59	61	66	67	70	71	74	76	79
	LIMEBANK	46	45	24	29	40	41	40	38	33	H.O.	33+33	68	42	43	44	47	49	52	54	56	59	61	64	67	70	73	76	79	82	85	89	88
	UPLANDS	6	9	25	28	26	23	23	21	22	H.O.	33	30	24	25	25	26	26	27	27	27	27	28	28	28	29	29	29	30	30	30	30	30
Nepean - South Total		79	75	72	78	93	91	93	87	84			124	95	99	105	111	114	119	129	134	140	144	150	154	160	168	173	179	183	189	195	198

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Appendix B

Integrated Regional Resource Planning – Near-Term Needs Hand Off Letter

ONTARIO POWER AUTHORITY

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June 27, 2014

Mr. Bing Young
Director, System Planning
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

Ottawa Area Regional Planning – Initiating Study or Development Work on Near and Mid-Term Transmission Solutions

Dear Bing,

The purpose of this letter is to:

- Hand off from the Ontario Power Authority (OPA) the lead responsibility for the planning process associated with the near-term transmission components of the Ottawa Region Integrated Regional Resource Planning (IRRP) process to Hydro One, and
- Request Hydro One Networks to initiate the development of wires solutions or implement the near-term transmission component of the integrated plan to meet the near- and medium-term reliability needs of the Ottawa Area.

This is consistent with the regional planning process endorsed by the Ontario Energy Board (OEB) as part of its Renewed Regulator Framework for Electricity.

The Ottawa Area Working Group (Working Group), consisting of staff from the OPA, the Independent Electricity System Operator (IESO), Hydro One and Hydro Ottawa, has been conducting an Integrated Regional Resource Planning (IRRP) process for the Ottawa Area since 2011. The IRRP process develops and analyzes forecasts of demand growth for a 20-year time frame, determines supply adequacy in accordance with the Ontario Resource and Transmission Assessment Criteria (ORTAC) and develops integrated solutions to address any needs that are identified.

While the IRRP process is not yet complete, a number of supply capacity and reliability issues in the near (within 5 year) and mid (5 to 10 years) term have been identified as not meeting the ORTAC planning standards in the Ottawa area. Furthermore, because of feasibility and the nature of the identified reliability issues, it has also been determined that wires solutions are the only reasonable means of addressing the identified needs. In such a situation, the Ontario Energy Board's (OEB) endorsed regional planning process provides for a "hand off" letter from the OPA to the lead transmitter, in this case Hydro One Networks, to initiate the development of wires

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solutions. This will permit Hydro One to develop and implement wires solutions to address the near-term needs in a timely fashion and commence early work associated with these solutions for their Regional Infrastructure Plan for the Ottawa area in advance of the completion of the IRRP.

Summarized below are four near-term needs along with proposed wires solutions identified for the Ottawa area by the Working Group for implementation by Hydro One.

1. Improve the reliability performance of Almonte TS and Terry Fox MTS by installing an in-line circuit breaker at Almonte TS on 230 kV circuit M29C between Cherrywood TS and Merivale TS. This work was identified early in the IRRP and is currently underway with a scheduled in-service date of Q2 2015.

2. Provide additional 230/115 kV autotransformation capacity at Hawthorne TS so as to relieve overloading of the existing autotransformers T5 and T6 there. The preferred alternative is to replace these lower rated units with standard 250 MVA units. The increased capacity is required now.

3. Provide increased supply capability for the downtown Ottawa 115 kV network to relieve overloading of the 115 kV circuit A4K from increased demand on this system. The preferred alternative is to rebuild the existing 115 kV single-circuit A6R to a double-circuit and extend it to Overbrooke TS. The need date is 2017.

4. Upgrade a section of 115 kV circuit S7M (the tap to Fallowfield TS) to increase its supply capability in order to supply a large customer load connecting to this circuit in the south Nepean area. The need date is 2019 or earlier.

In addition to the above, Hydro One has advised that the transformers and protection facilities at Bilberry Creek TS are approaching their end of life. Based on a 2020 end of life date for these facilities, a transmission and distribution development plan is required to supply the load served by Bilberry Creek TS either by refurbishing the station or alternately decommissioning the station and serving the load from other stations in the area.

The Working Group has identified these projects to address near- and mid-term needs. However, more detailed study and development work is required before these projects can be implemented. Continued development of these projects is best accomplished by Hydro One leading this effort as a lead transmitter and working with any relevant LDCs, guided by the information and requirements provided below from the IRRP process.

To facilitate the development of the wires solution, the OPA will provide Hydro One with the following information:

- Relevant system base cases
- Demand forecasts
- Conservation and distributed generation forecasts
- Any other relevant information

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We look forward to receiving information, results, recommendations and deliverables related to these four near and mid-term projects for the Ottawa area, as part of the Ottawa Working Group activities and continue to work with and support Hydro One on the implementation of these projects.

Best Regards,

R. F. Chow

Bob Chow
Director, Transmission Integration
Power System Planning Division
Ontario Power Authority

CC Working Group members:

Hydro Ottawa
Jim Pegg
Jenna Van Vliet
Morgan Barnes

Hydro One Distribution
Ashley Lebel
Donald Lau

Hydro One Networks
Farooq Qureshy
Jean Morneau
Konrad Witkowski
Jayde Suleman

IESO
Peter Drury

OPA
Kai Fung
Yvonne Huang
Tracy Garner
Luisa Da Rocha

CC Others:

OPA
Amir Shalaby
Nancy Marconi
Joe Toneguzzo
Nicole Hopper

IESO
Mark Wilson
Mike Falvo
Mauro Facca

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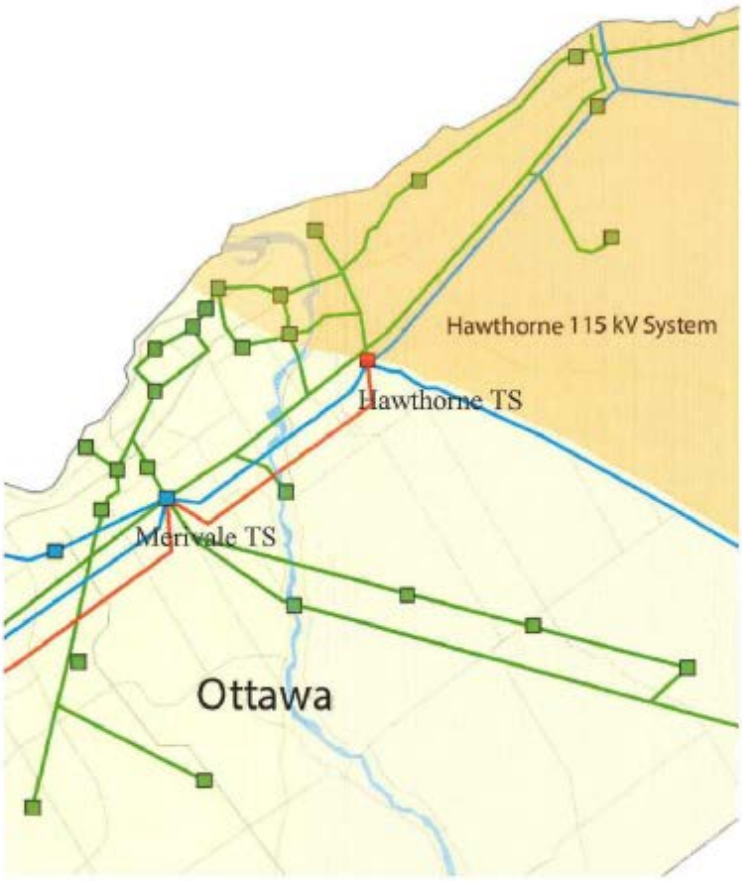
Attachment 1 – Project Objectives and Scope

Project 1: Hawthorne 115 kV System Autotransformer Upgrade

The 115 kV network in Ottawa area is connected to the 230 kV system through two autotransformer stations, Hawthorne TS, which serves the east half of the Ottawa area and Merivale TS, which serves the west half. The purpose of this project is to increase the 230/115 kV transfer capability at Hawthorne TS in order to meet the forecast load demand in the area while providing a level of reliability consistent with the IESO's ORTAC reliability standards.



There are currently four 230/115 kV autotransformers at Hawthorne TS. They supply about 630 MW of demand in east Ottawa. The 230/115 kV transformation capability at Hawthorne TS is limited by two of the existing autotransformers, T5 and T6. These two autotransformers are smaller in size, each with a rating of 225 MVA, while the other two autotransformers are rated at 250 MVA. Even at today's load level, planning studies done for this IRRP indicate that, following an outage of one of the autotransformers at Hawthorne TS, overload would result on the remaining T5 or T6 transformer under peak demand conditions. Orleans TS, which comes in

service in 2015 and transfer some load from the 115 kV to the 230 kV system, does not provide enough relief for the overloaded autotransformers. After that, continued load growth on the Hawthorne 115 kV system will worsen the overload.

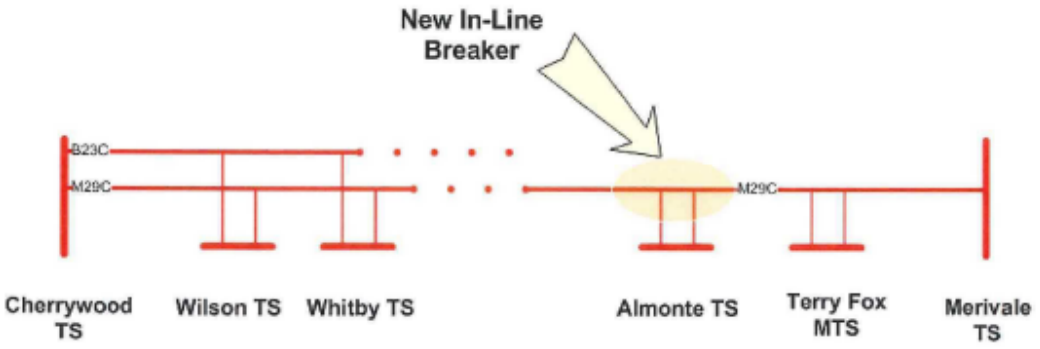
Since the overloading problem exists with today's load level, local generation option, which requires longer lead time, is not considered viable to address this need. Options of additional CDM were considered. However, significant demand reduction on the 115 kV system in the area will be required to provide sufficient relief for the overloaded autotransformers. 200 MW demand reduction can only provide roughly 10-year of relief on T5 and T6. On the other hand, both T5 and T6 are approaching 60-year-old in next few years. Replacement of these equipments is likely necessary in the near-term. Therefore, with support from the Working Group, the OPA recommends replacing the T5 and T6 autotransformers with 250 MVA units, with an estimated cost of $14 million. The estimated in-service date is 2017.

Project 2: Almonte in-line Breaker

Circuit M29C is a 320km long line that links Merivale TS in Ottawa to Cherrywood TS in Pickering. The line supplies two DESNs in the GTA, Wilson TS and Whitby TS; and two in Eastern Ontario, Almonte TS and Terry Fox MTS.

While Whitby TS and Wilson TS have a second 230kV supply from circuit B23C, both Almonte and Terry Fox MTS are on single line supply from circuit M29C. Any outage on the circuit - occuring about 7-10 times per year - means a complete interruption of supply to load customers at these two stations.

The Working Group identified the need for a breaker at Almonte early in the IRRP study and Hydro One is currently proceeding with the installation of a 230 kV breaker. This project will improve the reliability of the transmission supply to Terry Fox MTS and Almonte TS by eliminating the exposure of these stations to lightning related outages west of Almonte TS and is expected to reduce the probability of transmission-line related outages at these stations by about 80%.



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The Working Group noted that the breaker option does not protect against outages occurring on M29C on the Merivale side of the breaker. However, it does provide substantial improvement in reliability that can be achieved relatively quickly. It does not preclude development of other options that may be considered in the context of a long-term plan for the Nepean/Kanata area.

The reliability problem is due to the system configuration in this area, and is not driven by load growth. Therefore, additional CDM and local generation were not considered viable options to meet this need. This project is scheduled to be in service by Q2-2015, with an estimated cost of under $5 million.

Project 3: Downtown Transmission Line Rebuild

Downtown Ottawa is supplied by two 115 kV systems as shown in the figure below:

- from Merivale TS in the west through M4G and M5G
- from Hawthorne TS in the east through A4K, A5RK, A6R and A3RM

With forecasted load growth in the downtown area, the main section of A4K, from Hawthorne TS to Blackburn JCT, will exceed planning criteria starting 2017. Upon the contingency of losing the companion circuit A5RK, A4K will experience thermal overload.

This transmission line refurbishment project involves rebuilding a section of A5RK, between Overbrook TS and the junction with A6R, from a single circuit to a double-circuit line, and reconfiguring the supply to Overbrook TS to relieve the A4K circuit.

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The Working Group also discussed upgrading the main section of A4K to increase the supply capability of this circuit. However, this would involve upgrading a section that is proximately 8 km in length. In addition, due to the ampacity rating of the existing main section of A4K, upgrading may not provide significant incremental supply capacity to the area. For these reasons, the Working Group did not pursue the option of upgrading A4K.

Other non-wire options were considered. A 29 MW new hydroelectric facility was recently contracted through the OPA's Hydroelectric Standard Offer Program (HESOP). This is a run-of-the-river facility and hence based on planning assumption for run-of-the-river hydroelectric, very little capacity of the facility will be available during peak load condition. In addition, this HESOP facility has the milestone date for commercial operation of 2022. As the overload on A4K starts to arise in 2017, local generation option with this HESOP facility is not considered viable.

Additional CDM, such as Demand Response (DR) was also considered. However, to entirely address this need, over 30 MW of demand reduction will be required in the next 10 years and over 40 MW will be needed by 2032. Since the transmission option involves only refurbishing a short section of an existing line (less than 2 km in length), it would have a lower cost as compare to CDM options.

Therefore, with the support from the Working Group, the OPA recommends that Hydro One initiate work on the project. The cost of this project is currently estimated between $5 million and $6 million. Detailed project costs and in-service date will be determined as part of this work.

Project 4: S7M Upgrade

S7M is a 115 kV single circuit originated from Merivale TS. It supplies the Nepean / Kanata area in the west Ottawa. With forecasted load growth in the Nepean south area, the S7M tap to Fallowfield DS is expected to exceed its thermal capacity by 2019. This includes a large customer of Hydro Ottawa with bulk load of 20 MW who has recently requested connection at Richmond DS which is also supplied by the S7M tap, south of Fallowfield DS.

While the Working Group continues to develop options for additional supply to the Nepean south area for the longer-term, upgrading the existing S7M tap to Fallowfield DS is needed in the near-term in order to accommodate the connection of the bulk load customer. With the support from the Working Group, the OPA recommends that Hydro One work with Hydro Ottawa to determine the optimal upgrade configuration and proceed with the development work to upgrade the S7M circuit between STR 673 N JCT and Fallowfield DS.

Development of Transmission Options for Addressing the End-of-Life at Bilberry Creek TS

Bilberry Creek TS is a medium size 115 kV stepdown station located in East Ottawa. It was built in 1964 and is currently supplying about 80 MW of Hydro One Distribution and Hydro Ottawa customer load. Hydro One Transmission, who owns the station, informed the Working Group

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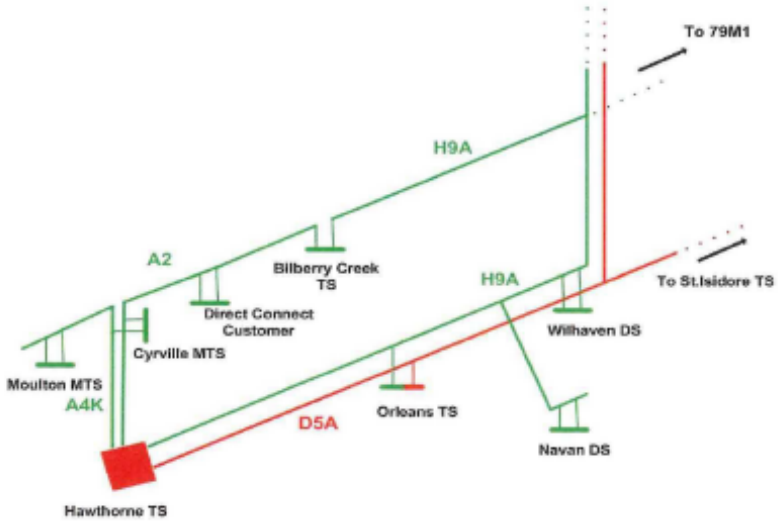
that the two transformers and the associated protection system at this station are near their end-of-life. For planning purpose, the end-of-life date is 2020. A decision is needed now to either refurbish the station and maintain the 115 kV system in the area, or decommission the station and transfer its load to other stations in the area by 2020.

Below is a figure showing the current supply arrangement for the East Ottawa / Orleans area.



The primary issue is to replace an end-of-life facility and is not related to load growth. Therefore, other options such as CDM and local generation are not viable to address this need. However, these other options will be considered as part of the integrated solutions for the area in the long-term, after the decision on addressing Bilberry Creek TS end-of-life is made. At this time, more detailed cost and technical information is required by the Working Group in order to make that decision. The Working Group agrees that the study work be handed-off to Hydro One at this time so that more detailed studies can be carried out by Hydro One.

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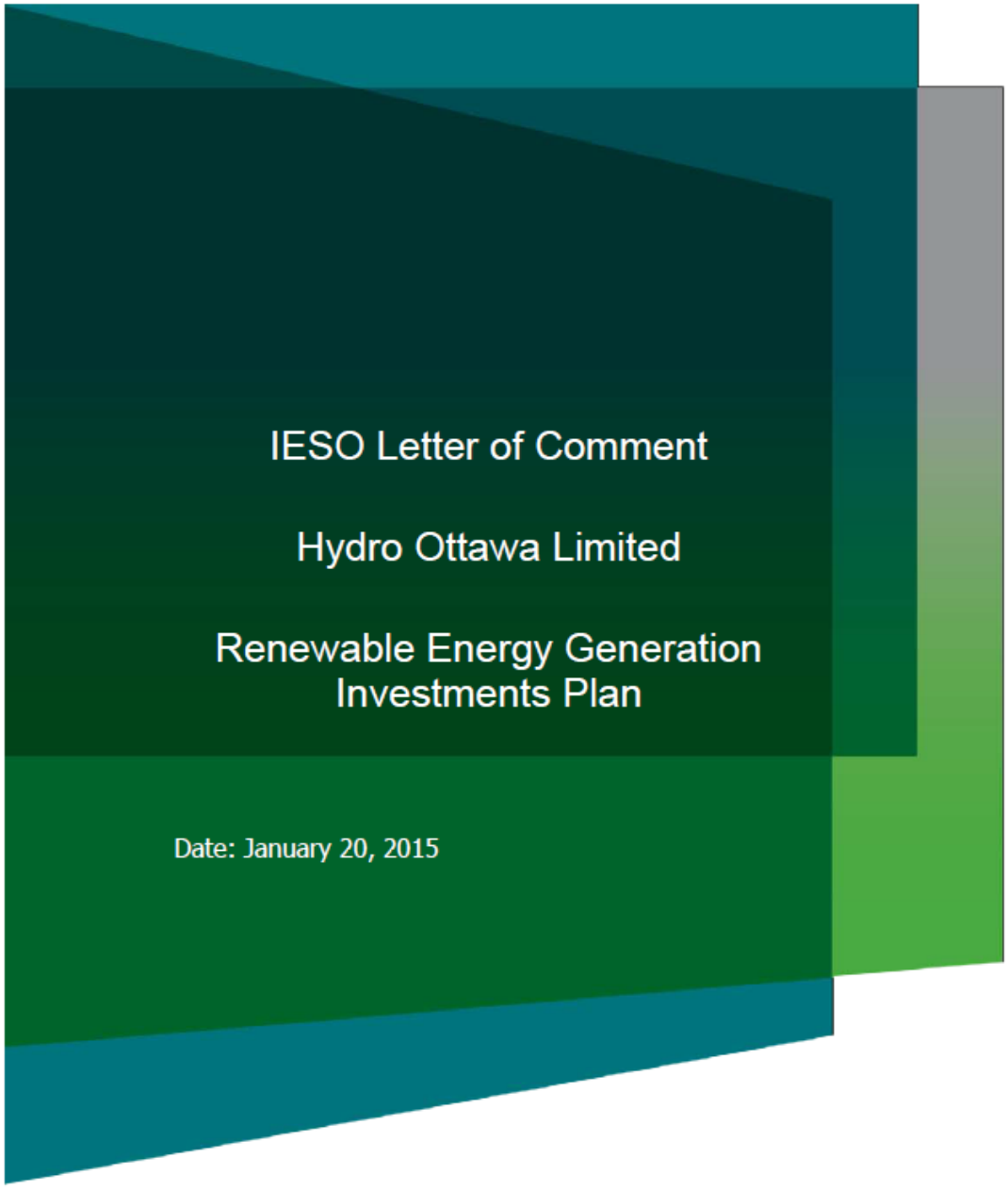
Appendix C

IESO Letter of Comment – REG Investments Plan



ieso
Independent Electricity System Operator

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Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority [1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the REG investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

Hydro Ottawa Limited – Distribution System Plan

On October 23, 2014 Hydro Ottawa Limited ("HOL") provided its Renewable Energy Generation Investments Information ("Plan") to the Ontario Power Authority as part of its 5-year Distribution System Plan. The IESO has reviewed HOL's Plan and has provided its comments below.

OPA FIT/microFIT Applications Received

Hydro Ottawa Limited indicates that presently it has connected 569 microFIT projects totalling 4,619 kW, and 88 FIT projects, totalling 10,792 kW. According to the IESO's information, as of November 2014, the OPA had offered contracts to 573 microFIT projects totalling 4,611 kW of capacity. The OPA contracted a total of 95 FIT projects, 88 of which have reached commercial operation or the Notice to Proceed stage ("NTP"). The remaining seven contracts have not yet reached NTP. The renewable energy generation connections information in HOL's Plan is therefore consistent with that of the IESO.

Additional Renewable Generation Procurement

Hydro Ottawa Limited also indicates that it has connected five facilities, with a total capacity of 18,580 kW, which were contracted as part of the Hydroelectric Contract Initiative; one facility, with a capacity of 6,378 kW, which was contracted as part of the RES I procurement; and two facilities, with a

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

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capacity of 10,700 kW, which were contracted as part of the RESOP procurement. This information is consistent with the IESO's records of previous OPA procurement programs.

In addition, Hydro Ottawa has noted that it has additional renewable and non-renewable generation connected to the distribution system (in the form of load displacement, net-metered and stand alone projects) which is not related to previous OPA procurement programs and which therefore cannot be verified by the IESO.

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

Hydro Ottawa Limited has been active in the Greater Ottawa regional planning process which has been ongoing since 2011. This regional planning process has now been merged into the Ontario Energy Board's regional planning process and is part of "Group 1" of the Board's 21 Ontario regions. The Integrated Regional Resource Plan ("IRRP") for this region is due to be completed in April, 2015.

Hydro Ottawa Limited identified six stations within their service territory that are restricted or constrained for additional renewable generation connection, four of which are owned by Hydro One, and two of which are owned by Hydro Ottawa. For Fallowfield DS, Hydro Ottawa has indicated that load growth in the area will be a mitigating factor, allowing additional renewable generation connections to the portion of the station which is currently constrained. For Leitrim MS, Hydro Ottawa has indicated the planned station investment which will remove the constraint.

The IESO looks forward to continuing to work with Hydro Ottawa Limited to complete an Integrated Regional Resource Plan for the Ottawa area, and appreciates the opportunity to comment on the information provided as part of its Distribution System Plan at this time.

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Appendix D

Worst Feeder Evaluation Methodology

HydroOttawa	TITLE: Worst Feeder Analysis	
RECOMMENDED: Jenna Van Vliet	NO:	REV:
APPROVED:		0
REV. DATE: 2011-08-30		

Worst Feeder Analysis

See Hydro Ottawa's Intranet site
for the latest revisions

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REVISION SHEET

Revision	Description of Change	Date	Initial
0	Original Document	2011-08-30	jvv

TABLE OF CONTENTS PAGE

1

1. Introduction

The basis for the evaluation of the Worst Feeders is to track and highlight priority areas that are consistently seeing issues, to then identify solutions to improve the reliability performance.

2. References

Canadian Electricity Association

3. Scope

This document describes the methodology used to determine and track the worst performing feeders on an annual basis. It does not describe methods used to improve feeder reliability.

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4. Definitions

Interruption: The loss of service to one or more customers.

Loss of Supply: Customer interruptions due to problems in the bulk electricity supply system.

Momentary Interruption: An interruption with a duration of less than 1 minute.

Scheduled Outage: Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

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5. Worst Feeder Evaluation

In order for HOL to be able to directly impact the reliability performance, only the causes for outages that can be reduced or eliminated by HOL intervention are included in the Worst Feeder Evaluation. This means that outages caused by Loss of Supply and Scheduled Outages are not included in the evaluation.

Four metrics are used in the evaluation process: the number of customers interrupted, customer hours of interruption, the number of interruptions a feeder sees annually and the number of momentary interruptions a feeder sees annually. The worst feeders are defined by those with: the highest number of customers interrupted (SAIFI), the highest number of customer hours interrupted (SAIDI), the highest number of interruptions (FEMI) and the highest number of momentary interruptions (MAIFI). In the evaluation, the metrics are each given a weighting according to their impact on a feeder's overall reliability. The number of customers interrupted, the number of customer hours of interruption and the number of interruptions are all equally weighted by a factor of 1, while the number of momentary interruptions is given a weighting of ½. This weighting is based on the fact that not all of the reclosing devices in the system are monitored and therefore we currently do not report on MAIFI.

To calculate each metric, the maximum number of customers, the total number of customer hours, the number of outages and momentary outages seen has to be determined for each feeder in the system for the previous 3 years. The 3-year average for the four categories, for each feeder, is then calculated based on the 3 year period. From the 3-year average, a per-unit value is then calculated. To calculate the per-unit value for the 3-year average of the maximum number of customers and the total number of customer hours, the 3-year average values are divided by 30,000. The 30,000 is based on an assumption that no feeder should contribute more than 10% towards the corporate target of 1.0 for both the 3-Year average SAIDI and SAIFI values with a total customer count of 300,000. The 3-year average number of outages is divided by 10, since HOL reports on $FEMI_{10}$, to determine the per-unit value for each feeder. The 3-year average number of momentaries is divided by 25, since no feeder has seen more than 25 momentary outages annually to date. This number may be adjusted as a specific target for momentary outages is chosen. To attain the overall feeder rating the four per unit values are multiplied by their associated weighting (1 for customers interrupted, 1 for customer hours, 1 for number of outages and ½ for number of momentaries) and then summed.

The score of each feeder gives a picture of the feeder's performance over the last three year period, but does not take into consideration whether the feeder's reliability has been improving or deteriorating. To determine whether the feeder's reliability is improving the feeder's Score (weighted per-unit ranking as outlined above) is evaluated over the previous three year period. When the Score is plotted for the three year period, if the overall trend is increasing (positive slope) then the feeder's reliability has been deteriorating, if the overall trend is decreasing (negative slope) then the feeder's reliability has been improving and if the slope is relatively flat, then the reliability has remained consistent. See Figure 1 below, Feeder 1 has deteriorating reliability, Feeder 2 has improving reliability and Feeder 3 has had relatively consistent reliability.

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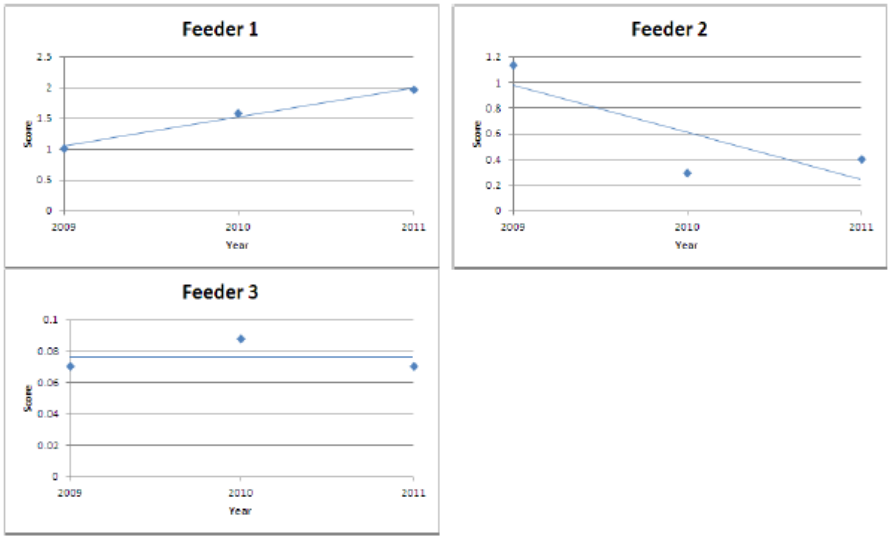
Figure 1: Feeder Score



To incorporate whether the feeder's reliability is improving or deteriorating, the linear slope of the Score for the previous three years is calculated. This is accomplished by determining the Least Squares Fit to the Score for the three year period. The formula assumed is shown below.

$$m = \frac{\sum x \cdot y - 3\overline{x}\overline{y}}{\sum x^2 - 3\overline{x}^2}$$

Where, m = Slope – Least Squares Fit
x = Year
y = Score

The slopes for Feeder 1, Feeder 2, and Feeder 3 from the charts above are calculated below.

$$m_{Feeder1} = \frac{[(2009 \cdot 1.02) + (2010 \cdot 1.59) + (2011 \cdot 1.97] - 3[(2009 + 2010 + 2011)/3] \cdot [(1.02 + 1.59 + 1.97)/3]}{(2009^2 + 2010^2 + 2011^2) - 3(2009 + 2010 + 2011)/3)^2}$$

$$m_{Feeder1} = \frac{9206.75 - 9205.80}{12120302 - 12120300}$$

$$m_{Feeder1} = \frac{0.95}{2.00}$$

$$m_{Feeder1} = 0.48$$

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$$m_{Feeder2} = \frac{[(2009 \cdot 1.13) + (2010 \cdot 0.30) + (2011 \cdot 0.41)] - 3[(2009 + 2010 + 2011)/3] \cdot [(1.13 + 0.30 + 0.41)/3]}{(2009^2 + 2010^2 + 2011^2) - 3(2009 + 2010 + 2011)/3)^2}$$

$$m_{Feeder2} = \frac{9970.25 - 9971.89}{2.00}$$

$$m_{Feeder2} = \frac{-0.72}{2.00}$$

$$m_{Feeder2} = -0.36$$

$$m_{Feeder3} = \frac{[(2009 \cdot 0.07) + (2010 \cdot 0.09) + (2011 \cdot 0.07)] - 3[(2009 + 2010 + 2011)/3] \cdot [(0.07 + 0.09 + 0.07)/3]1}{(2009^2 + 2010^2 + 2011^2) - 3(2009 + 2010 + 2011)/3)^2}$$

$$m_{Feeder3} = \frac{14095.99 - 14095.73}{2.00}$$

$$m_{Feeder3} = \frac{0.00}{2.00}$$

$$m_{Feeder3} = 0.00$$

The slopes are then unitized based on a scale from -1 to +1. This implies that the feeder with the fastest improving reliability will have a Trend closest 0, while the feeder with the quickest deterioration will have a trend closest to 1 and feeders who's reliability has remained consistent will sit near 0.5. The unitizing is done with the following equation.

$$Trend = \frac{m - Min(m)}{Max(m) - Min(m)}$$

$$Trend = \frac{m - (-1)}{1 - (-1)}$$

$$Trend = \frac{m + 1}{2}$$

The Trends for Feeder 1, Feeder 2 and Feeder 3 are calculated below.

$$Trend_{Feeder1} = \frac{0.48 + 1}{2}$$

$$Trend_{Feeder1} = 0.74$$

$$Trend_{Feeder2} = \frac{-0.36 + 1}{2}$$

$$Trend_{Feeder2} = 0.32$$

$$Trend_{Feeder3} = \frac{0.00 + 1}{2}$$

$$Trend_{Feeder3} = 0.50$$

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To determine the overall Rank for each feeder the Trend is multiplied by the Score. The Rank for the feeders is then sorted from highest to lowest score, which sorts the feeders from worst reliability performer to best.

To visually inspect the Worst Feeders, a plot of Trend versus Score can be used. See the example in Figure 2 on the following page.

Since Trend is the unitized slope value, between 0 and 1, a Trend between 0 and 0.5 implies a negative slope, or improving reliability, and a Trend between 0.5 and 1 implies a positive slope, or deteriorating reliability. It can be seen in Figure 2 that the majority of the feeders fall within a Score from 0 and 0.5 (Approx. 95%) and a Trend around 0.5. It can therefore be interpreted that the feeders that need to be evaluated can be determined by eliminating the feeders with a Score below 0.5, and a Trend below 0.5 See Figure 3.

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Figure 2: Feeder Rank - Overall

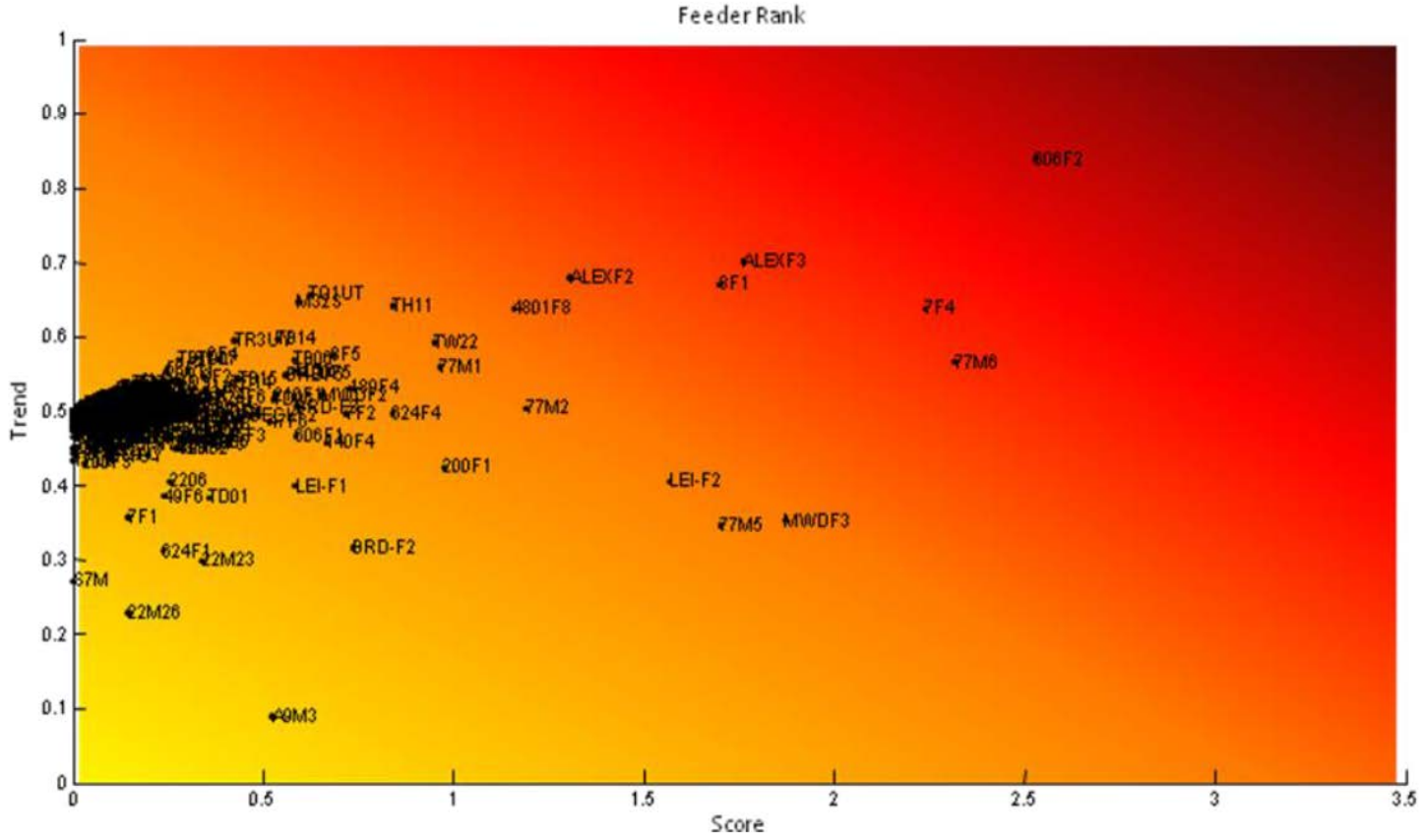

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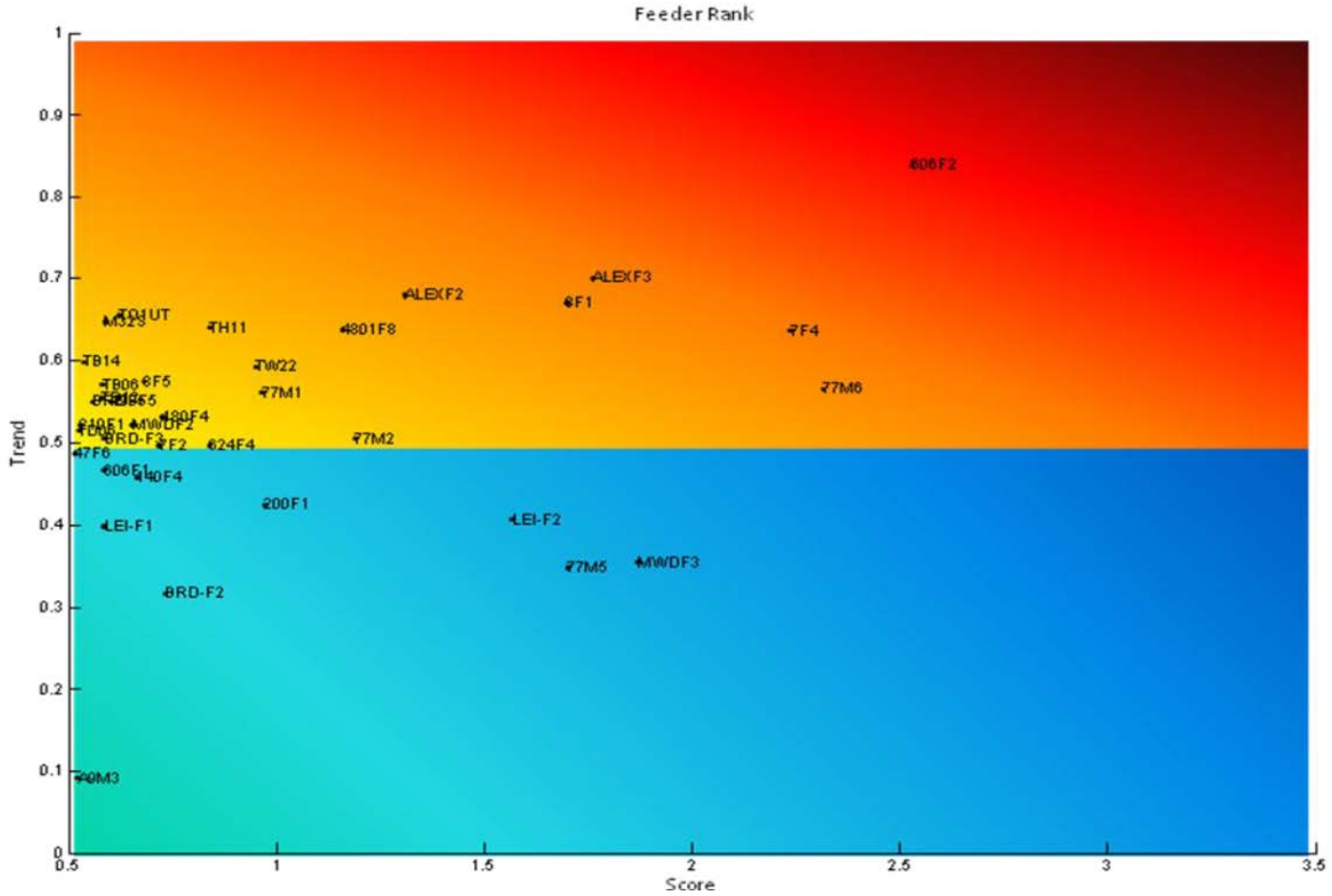
Figure 3: Feeder Rank – Feeders Requiring Evaluation



6. Worst Feeder Evaluation Process

The following section outlines the steps to determine the Worst Feeder List.
See Table 1 for the referenced rows and columns for steps 1-4.

1. Determine the Number of Outages, the Number of Momentary Outages, Maximum Customers Interrupted, and the Total Customer Hours of Interruptions for all feeders.
    - Fill in the information for Columns C, D, E & H, I, J & M, N, O & R, S, T
2. Calculate the 3-year average for the Number of Outages, the Number of Momentary Outages, Maximum Customers Interrupted, and the Total Customer Hours of Interruptions for all feeders.
    - (Value Year 1 + Value Year 2 + Value Year 3) / 3
    - Calculate columns F & K & P & U
    - Ex: *F1 = (C1+D1+E1)/3*
3. Calculate the per unit values for the Number of Outages, the Number of Momentary Outages, Maximum Customers Interrupted, and the Total Customer Hours of Interruption for all feeders.
    - 3 Year Average / Maximum Allowable Value
    - Maximum Allowable Value:
        i. Number of Outages: 10
        ii. Number of Momentary Outages: 25
        iii. Maximum Customers Interrupted: 30,000
        iv. Total Customer Hours of Interruption: 30,000
    - Calculate Columns G & L & Q & V
    - Ex: *G1 = F1/Max Allowable Value)*
4. Calculate the Score for all feeders
    - (Per Unit Number of Outages) + 0.5*(Per Unit Number of Momentary Outages) + (Per Unit Maximum Customers Interrupted) + (Per Unit Customer Hours of Interruptions)
    - Calculate Column B

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- Ex: *B1 = G1 + 0.5*L1 + Q1 + V1*

See Table 2 for the referenced rows and columns for steps 5-8.

5. Calculate the slope for each feeder using the Least Squares Fit Method.

   - $m = \frac{\sum x \cdot y - 3\overline{xy}}{\sum x^2 - 3\overline{x^2}}$ Where, m = slope, x = year and y = score
   - Calculate Column E
   - Ex: *E1 =(SUMPRODUCT(C1:E1,C2:E2)-3*AVERAGE(C1:E1)*AVERAGE(C2:E2))/(SUMSQ(C1:E1)-3*AVERAGE(C1:E1)^2)*

6. Calculate the Trend for each feeder, unitizing to a scale of -1 to +1.

   $$Trend = \frac{m - Min(m)}{Max(m) - Min(m)}$$

   - $Trend = \frac{m-(-1)}{1-(-1)}$

     $Trend = \frac{m+1}{2}$

   - Calculate Column F
   - Ex: *F1 =(E1+1)/2*

7. Calculate the Rank for each feeder.

   - *Rank = Score x Trend*
   - Calculate Column G
   - Ex: *G2 = D2*F2*

8. Arrange the Rank in descending order, for largest to smallest.

   - Arrange Column G in descending order – This arranges the feeders from worst performer to best performer.

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Table 1: 2010 Feeder Score

		Score	Number of Interruptions					Number of Momentary Interruptions					Customer Hours					Maximum Customers				
	Feeder	2010	2008	2009	2010	Average	Per Unit	2008	2009	2010	Average	Per Unit	2008	2009	2010	Average	Per Unit	2008	2009	2010	Average	Per Unit
1	Worst Feeder 1	2.91	36	24	12	23.67	2.37	2	1	4	2.33	0.09	12317	13439	1766	9170.33	0.31	6796	7562	2836	5731.00	0.19
2	Worst Feeder 2	1.59	5	8	5	6.00	0.60	11	4	1	5.33	0.21	9295	13457	18374	13708.67	0.46	5245	12572	20522	12779.67	0.43
3	Worst Feeder 3	2.06	13	18	8	13.00	1.30	6	7	3	5.33	0.21	1261	20479	453	7397.67	0.25	4483	31764	239	12158.67	0.41
4	Worst Feeder 4	1.86	15	14	13	14.00	1.40	1	16	12	9.67	0.39	1447	4469	983	2299.67	0.08	838	10366	5627	5610.33	0.19
5	Worst Feeder 5	1.61	14	12	18	14.67	1.47	1	1	0	0.67	0.03	648	7671	661	2993.33	0.10	233	1840	956	1009.67	0.03
6	Worst Feeder 6	1.77	11	14	15	13.33	1.33	6	0	0	2.00	0.08	8883	1903	8468	6418.00	0.21	11497	2467	2676	5546.67	0.18
7	Worst Feeder 7	1.40	8	8	7	7.67	0.77	1	0	6	2.33	0.09	7140	9270	16841	10750.33	0.36	3482	5795	11161	6812.67	0.23
8	Worst Feeder 8	1.13	8	9	6	7.67	0.77	2	3	2	2.33	0.09	1204	2032	6514	3250.00	0.11	4638	4719	8978	6111.67	0.20
9	Worst Feeder 9	0.99	7	14	6	9.00	0.90	1	0	0	0.33	0.01	279	3376	667	1440.67	0.05	140	2342	535	1005.67	0.03
10	Worst Feeder 10	2.10	32	7	8	15.67	1.57	1	2	0	1.00	0.04	17456	3894	1680	7676.67	0.26	17890	4262	749	7633.67	0.25

Table 2: 2010 Feeder Slope, Trend & Rank

		Score			Slope	Trend	Rank
	Feeder	2008	2009	2010	2010	2010	2010
1	Worst Feeder 1	2.50	2.80	2.91	0.21	0.60	1.76
2	Worst Feeder 2	0.62	1.02	1.59	0.48	0.74	1.18
3	Worst Feeder 3	1.79	2.16	2.06	0.14	0.57	1.17
4	Worst Feeder 4	1.44	1.79	1.86	0.21	0.60	1.12
5	Worst Feeder 5	1.10	1.33	1.61	0.26	0.63	1.02
6	Worst Feeder 6	1.75	1.84	1.77	0.01	0.51	0.90
7	Worst Feeder 7	1.06	1.00	1.40	0.17	0.58	0.82
8	Worst Feeder 8	0.55	0.88	1.13	0.29	0.64	0.72
9	Worst Feeder 9	0.70	0.91	0.99	0.14	0.57	0.57
10	Worst Feeder 10	3.02	2.52	2.10	-0.46	0.27	0.56

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7. Worst Feeder Trending

In order to determine whether or not improvements are being seen on the worst feeders from one year to the next – as a feeder may appear in the top ten for a few years as the rating is based on a 3-year average – trending from year to year must be evaluated.

For three years following the first time a feeder is seen on the Top Ten listing the slope is tracked to determine whether or not the reliability performance is improving. Three years is used since any improvements to the feeder will be implemented in the following budget year, then results can be tracked for the next two years.

As described above, if the overall linear trend is decreasing for the following three years, then improvements are being seen on the feeder, if the overall trend is increasing or remaining constant, then further evaluation, and possible intervention is required.

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Appendix E

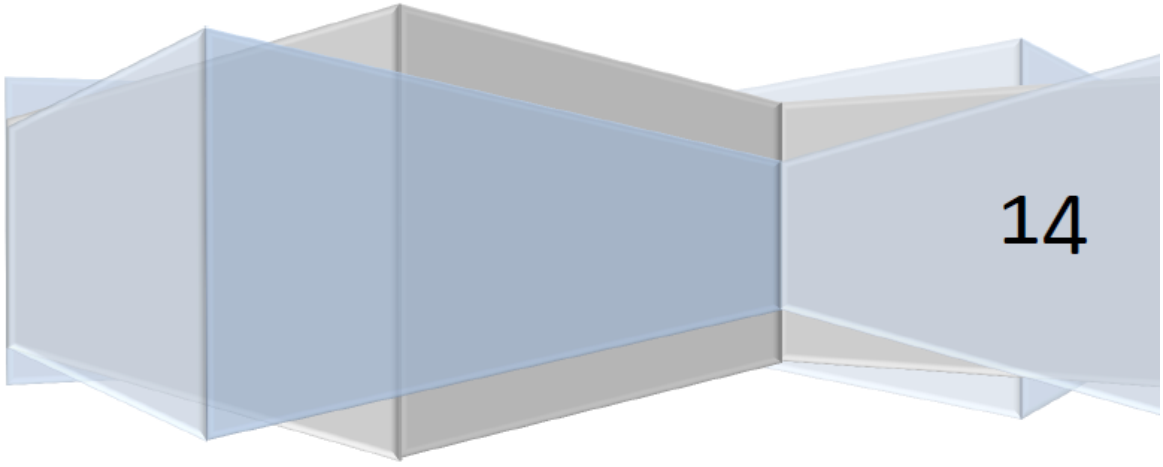
City of Ottawa Community Design Plan Summary

Hydro Ottawa Limited

Community Design Plans

Approved by City Council for Implementation

Annie Williams



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This document contains a summary of all Community Design Plans approved by the City of Ottawa as of October 2014. The purpose of this report is to demonstrate the expected growth in the city over the next few years. Some projects may already be underway while others are planned for the long term. This report is specifically focused on the consequences of City expansion projects to Hydro Ottawa's electrical distribution system.

Each CDP summary states the boundaries of the study area, any relevant transportation projects within the study area that may affect Hydro Ottawa's assets, and a brief description of the development proposed for the area. Full CDP documents are available on the City of Ottawa's website at http://ottawa.ca/en/city-hall/planning-and-development/community-plans-and-design-guidelines/community-plans-and-studi-0.

It is expected that there will be more than 214MW of load growth in the City of Ottawa over the next 20 years. Hydro Ottawa's distribution system does not currently have the capacity to supply these additional loads in some areas. System expansion and relocation will need to occur alongside these City plans and additional station capacity is being considered.

1

Table of Contents

1

CDP Summary

Study	Study Area (ha)	GFA (ha)	No. Res. Units	Land Use Type	Expected Load (MW)	MVA (PF=0.9)
Barrhaven South CDP	500	188.9	6,862	Mixed-Use	14,253	15,837
Bank Street CDP	101			Mixed-Use	0	0
Bayview Station District CDP	29.5	55		Mixed-Use	4,146	4,607
Bayview/Somerset Area Secondary Study	89.7		1,590	Mixed-Use	3	4
Beechwood CDP	22		819	Mixed-Use	2	2
Cardinal Creek Village Concept Plan	208	95	3,500	Mixed-Use	7,168	7,965
Carp Road Corridor CDP	2475		0	Commercial	0	0
Village of Carp CDP	49.5		543	Mixed-Use	1	1
Village of Constance Bay Community Plan	114		204	Mixed-Use	0	0
Downtown Ottawa Urban Design Strategy					0	0
East Urban Community (Phase 1 Area) CDP	570		3,498	Mixed-Use	7	8
East Urban Community (Phase 2 Area) CDP	240		1,726	Mixed-Use	3	4
Escarpment Area District Plan				Mixed-Use	0	0
Fernbank CDP	674	310	11,000	Mixed-Use	23,390	25,989
Greely CDP	1276		729	Mixed-Use	1	2
Leitrim CDP	500	362.3	5,300	Mixed-Use	27,321	30,356
Mer Bleue CDP	160	113.7	3,000	Mixed-Use	8,577	9,530
Kanata West Concept Plan	887		5,000	Mixed-Use	10	11
North Gower CDP	278	208	520	Mixed-Use	15,680	17,422
Old Ottawa East CDP	158		2,250	Mixed-Use	5	5
Orleans Industrial Park Study	316	18.7	0	Commercial	1,410	1,566
Queensway Terrace North	140				0	0
Richmond Road/Westboro CDP	270		3,970	Mixed-Use	8	9
Richmond Road/Westboro Transpo Plan					0	0
Riverside South CDP	1800	1450	18,300	Mixed-Use	109,338	121,486
Scott Street CDP	57.7		1,500	Mixed-Use	3	3
South Nepean Town Centre CDP	165	35	11,000	Mixed-Use	2,660	2,956
St. Joseph Boulevard Corridor Study	67.3			Mixed-Use	0	0
Uptown Rideau CDP	21			Mixed-Use	0	0
Transit-Oriented Development (TOD) Plans					0	0
Village of Richmond CDP	879			Residential	0	0
Wellington Street West CDP	232		950	Mixed-Use	2	2

*Expected load should be greater than shown in table due to lack of information

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Barrhaven South CDP

Boundaries: Jock River, Highway 416, Barnsdale Rd, Jockvale Rd & Greenbank Rd
Transportation projects: Relocation and widening of Greenbank Rd (also upgrade to 4-lanes south of Cambrian Rd), New 4-lane structure over Jock River, Cambrian Rd widening

The area currently contains a few farms and rural residential homes. The plan is to create a complete residential community that contains a full range of housing choices and a broad complement of support services and facilities. This will include residential housing, commercial buildings, community centres and schools.

Bank Street CDP

Boundaries: Bank St - Rideau River to Ledbury Park (ie. Riverside Dr to CN Rail Line)
Transportation Projects: 2 Transitway stations + LRT station within walking distance, 3 Intersection modifications

The current land uses along Bank St are predominantly commercial, with some residential, office and industrial uses. The Bank St corridor will become a vibrant mixed use area with diverse housing, shops and services. The goal is to transform the area from a retail strip into a central spine for a new higher-density community.

Bayview Station District CDP

Boundaries: Revolves around Bayview Station, Bayview Rd, Albert St, City Centre Ave, Somerset St W
Transportation Projects: LRT station, Existing O-Train line to become major LRT route (BRT to LRT)

A large portion of the study area is publicly owned, such as the rail corridor and the Tom Brown Arena. The area also contains some smaller-scale residential and commercial properties. The focus is on transit-oriented development in the area around Bayview Station. It will include residential buildings, mixed-use commercial and small scale industrial buildings. The CDP notes that existing underground utilities do not follow municipal rights-of-way and development will need to consider avoiding or relocating these services. It is not specified whether these utilities include Hydro.

Bayview/Somerset Area Secondary Study

Boundaries: Lebreton Flats to Tunney's Pasture, Bayview Road, Canadian Pacific Railway, Transitway, Ottawa River Parkway
Transportation Projects: Traffic circle at Burnside/Bayview

The site is currently occupied by a number of City operations such as snow disposal. Bayview Road will become the community's main street, and there will be a mix of medium density housing forms as well as retail space. It should be noted that many properties in the study area have soil contamination.

1

Beechwood CDP

Boundaries: Beechwood Ave - St. Patrick St Bridge to Beechwood Cemetery
Transportation Projects: No Relevant Projects

Beechwood Avenue currently has a wide variety of shops. The public prefers low-rise or medium-rise building heights. It is mentioned that hydro poles and wires should be removed, if possible. It is anticipated that there will be a new grocery store, other small stores, residential buildings and urban plazas.

Cardinal Creek Village Concept Plan

Boundaries: Ottawa Road 174 & Ottawa River, Cardinal Creek, Frank Kenny Rd/Ted Kelly Ln
Transportation Projects: Rapid Transit Corridor may be extended into study area

These lands currently have large lot rural residential, institutional and nursery/landscape uses. 50% of the area is pasture. The intent is to create a complete residential community with a full range of housing choices that is complemented and supported by appropriate community facilities such as parks and schools, while providing opportunities to work and shop in close proximity to the residential neighbourhoods. A 'center' to the village was considered an important community-defining element of the plan and accordingly, the intersection of the proposed north-south major collector road and Old Montreal Road was identified as a central area. In this location, a variety of land uses (such as local commercial uses, higher density residential uses and a neighbourhood park) have been provided to create an active, interesting and diverse 'Village Core'. The 'Village Core' will be supported by the creation of a traditional main street character along Old Montreal Road, and will support potential future transit service along this road. Hydro Ottawa has confirmed that there is plant in reasonable proximity to the study area.

Carp Road Corridor CDP

Boundaries: Carp Rd - Rothbourne Rd to March Rd
Transportation Projects: Carp Rd widening to 4 lanes (Stittsville boundary to Richardson Side Rd)

The Carp Road Corridor currently contains country lot residential subdivisions, a golf course, commercial and agricultural properties. The objective is to promote the corridor as a rural employment area which is an attractive base for a wide range of industrial and commercial uses.

Village of Carp CDP

Boundaries: Carp River, Carp Hills
Transportation Projects: Former CN Rail line protected as corridor for future public transit

There are 2 areas being discussed: the Village Core and the residential areas. The Village Core contains heritage buildings, and will be the primary focus of Carp's economic activity. The predominant uses in the Core will be commercial, recreational and institutional, with residential uses being encouraged as part of a mixed-use development. Commercial and retail uses will not be permitted in the residential areas.

1

Village of Constance Bay Community Plan

Boundaries: Ottawa River
Transportation Projects: Road links from Allbirch to Kilmaurs Side Rd (to provide 2nd access into area)

There is limited potential for growth, but the Village will grow slowly over the next 20 years in two ways: new subdivision in the undeveloped land, and the conversion of cottages to permanent homes. Constance Bay will be a residential-focused area, with some commercial development in the Village. This includes a new shopping area, medical centre and day care.

Downtown Ottawa Urban Design Strategy

Boundaries: Ottawa's Downtown Core
Transportation Projects: This document encompasses many upcoming transportation projects

Over the next 20 years, this design strategy will help set the stage for a renewed physical environment for the downtown core. This is a strategic document that can be used by several parties as a tool to guide future development projects in the downtown area. The strategy sets the proper priorities on improvements for realization over the 20-year time frame.

East Urban Community (Phase 1 Area) CDP

Boundaries: Mer Bleue Rd, Former Canadian Pacific Railway line, NCC Greenbelt, Hydro corridor
Transportation Projects: Alignment of the future Blackburn Hamlet By-pass Extension, Navan Rd and Mer Bleue Rd widening to 4-lane divided arterials, Belcourt Boulevard Extension, 2 LRT stations

There are existing structures in the study area, but the land is largely undeveloped. The Orleans projected population is expected to increase steadily over the next 15 years to approximately 20,000 more people. More housing is needed for this additional population. There are several Official Plan (OP) targets for residential development that should be met, such as: achieve a density of 29 units/net ha for singles, semis and towns, requirement of 10% apartments, at least 30% multiples, and maximum 60% singles and semi-detached dwellings. There are 2 proposed transit stations and a Mixed Use Centre (700-850 units).

East Urban Community (Phase 2 Area) CDP

Boundaries: Former Canadian Pacific Railway line, Mer Bleue Rd, Renaud Rd, Phase 1 boundary
Transportation Projects: Mer Bleue Rd realignment, Future VIA Rail high-speed passenger train

The majority of the study area is currently covered with open pasture or wooded areas. Existing structures are predominantly residential dwellings, with some small commercial uses. The East Urban Community's designation as a Developing Community in the City of Ottawa Official Plan sets the requirement for the completion of a CDP for the lands. There will be more residential housing, commercial sites, 3 elementary schools, and a fire station. It should be noted that there are multiple statements in the CDP regarding burying hydro lines along particular roads.

1

Escarpment Area District Plan

Boundaries: Lebreton Flats, Garden of the Provinces, Bay Street, Laurier Avenue
Transportation Projects: New roads (no impact on existing/proposed transit system)

Over the next 15 years, the Escarpment District will develop into a diverse and attractive downtown community. This will include new residential developments (various types – ex. high rise buildings), commercial buildings, and an Ottawa Technical High School. It is noted that hydro services are located adjacent to the study area, and that Hydro Ottawa will be contacted in advance of site plan approval to confirm the adequacy and availability to service the proposed development.

Fernbank CDP

Boundaries: Stittsville, Carp River, Terry Fox Dr, South of Hazeldean Rd to Fernbank Rd
Transportation Projects: Widening of Hazeldean Rd, Terry Fox Dr, Kanata West road network, Extension of Western Transitway, Extension of rapid transit corridor & north-south arterial

The study area currently contains rural and agricultural uses, including 2 transmission corridors. Development will include residential and commercial uses. It has been noted that Hydro Ottawa has confirmed that there is plant in reasonable proximity of the study area, and that there is adequate supply to service the Fernbank community.

Greely CDP

Boundaries: Mitch Owens, Sale Barn, Fox Valley, Snake Island Rd
Transportation Projects: Updated Road Network

The objectives of this CDP are to provide more residential dwellings, and to develop the Village Core, which will include residential, commercial and institutional uses. There will be a shopping centre. Note that the CDP mentions an expansion of utility services which will be installed efficiently to minimize disruptions.

Leitrim CDP

Boundaries: Leitrim Rd, Bank St, Albion Rd
Transportation Projects: Future LRT Station (North-South LRT Corridor) and Park & Ride Lot, 4-lane Bank St & Albion Rd, 2-lane Leitrim Rd & Earl Armstrong Dr Extension

The majority of Leitrim is presently undeveloped, but there are existing commercial, institutional, industrial and residential uses throughout the area. The plan involves adding 3 mixed use centres along Bank Street to accommodate commercial, institutional, residential and service uses. There will be 4 elementary schools, higher density residential uses and 10 residential neighbourhoods.

1

Mer Bleue CDP

Boundaries: Hydro Corridor, Mer Bleue Rd, Tenth Line Rd, Southern Urban Boundary
Transportation Projects: East-West Transit Expansion along northern boundary (Stations at Mer Bleue & Tenth Line), Blackburn Hamlet By-pass Extension, Innes Rd Widening 4-lanes

The CDP area is part of the Orleans Expansion Area. There are currently residential and rural uses, developing commercial uses and a HONI corridor. The plan will potentially involve 2 new schools, as well as residential, commercial and mixed-use development. The CDP notes that private utilities shall be permitted in all land use designations, utilities must confirm the ability to provide service prior to development, and developers should consult with utilities early on.

Kanata West Concept Plan

Boundaries: Highway 417, former: Township of West Carleton, Township of Goulbourn, City of Kanata
Transportation Projects: Transit Corridor Extension (Kanata Town Centre to CTC), Highway 417 widening 6/8 lanes, Terry Fox Dr Widening (Upgrade Interchange), Hazeldean Rd Widening, Eagleson Rd Widening, Construct Castlefrank Rd Interchange
Existing uses within the area are limited, but include the Canadian Tire Centre (CTC) and related offices, the City of Ottawa Works Yards, the Wesleyan Church of Canada, and some residential dwellings. The concept plan involves creating office uses, housing, retail, institutional and entertainment uses. The Mixed Use area is the heart of this new community with 3 integrated land use concepts – the Community Core Zone, the Major Facilities Zone, and the Institutional/Corporate Campus Zone. There will also be a Prestige Business Park, and 2 residential areas. The plan notes that the proposed development area is split between HONI and HOL, and it states that HONI will act as the lead representing both utility companies. It is stated that there is adequate capacity to serve initial loads, and new sources will be brought into the area as loads exceed capacity.

North Gower CDP

Boundaries: Centered on crossing of 3 roads: Prince of Wales, Roger Stevens, Fourth Line
Transportation Projects: Multi-Use Pathway Plan (including new sidewalks), Future Local Road Network

North Gower is a vibrant farming community in a rural setting. There are currently some small commercial uses in the Village Centre. The goal of the CDP is to provide a variety of business to support the community, and to provide more housing for residents. There will be added commercial uses. It is noted that some residents would like overhead lines buried within the Village Centre. They would like to see upgraded street lighting for safety purposes, along certain streets such as Prince of Wales, Roger Stevens and Fourth Line. They would also like to see lighting throughout new subdivisions and on the bridges.

Old Ottawa East CDP

Boundaries: Rideau River, Rideau Canal, Riverdale, Highway
Transportation Projects: Widen Sidewalks (Main St, Lees Ave), Roundabout at Main/Riverdale Intersection, Narrow Main St from 4 to 3 lanes

The study area primarily focuses on Main Street, along which there are some clusters of retail uses. A large percentage of the land is occupied by institutions and there is a large portion of residential space.

1

The plan involves intensifying lots in a mixed-use format, adding residential and commercial uses, and enhancing a mixed-use centre precinct at the east end of Lees Ave (near Ottawa University campus). The CDP notes that priority will be given to the burial of overhead wires in some locations.

Orleans Industrial Park Study

Boundaries: Innes Rd, Hydro Corridor, Pagé Rd, Tenth Line Rd
Transportation Projects: Innes Rd Expansion 4-lanes, Widening of Mer Bleue Rd & Tenth Line Rd

The study area currently contains residential and commercial uses. There is a HONI Transmission Corridor on the south border of the study area. Proposed development includes a 45 m^2 commercial development and an 18.7 ha snow disposal facility. The industrial park will be modified without disturbing the surrounding residential areas.

Queensway Terrace North

Boundaries: Carling Ave, Transitway, Queensway, Pinecrest Rd
Transportation Projects: No Relevant Projects
This study was undertaken in response to increasing community concerns over the number of residential triplex conversions within the area, which are not in compliance with Zoning By-law 1998. The goal of this study was to conduct a review of the likely forms, locations and appropriate levels of intensification, the ability of existing infrastructure to accommodate growth, and the potential impact of evolving City Council intensification policies on this neighbourhood. The results of this study do not appear to directly affect Hydro Ottawa or any of its assets.

Richmond Road/Westboro CDP

Boundaries: Ottawa River, Island Park Dr, Byron Ave, Ottawa River Parkway Extension
Transportation Projects: Potential Transitway Station in New Orchard Area

This CDP was undertaken because neighbouring residential communities were concerned with several rezoning applications for substantial increases in maximum building height. They viewed increased building heights as being incompatible with the existing character of Richmond Road. The study area currently contains a mix of residential housing types, retail, office, institutional, commercial and industrial uses. The study area has been divided into several sectors. Between all of them, there will be new residential communities with commercial mixed-use buildings, offices, institutional and industrial development. The CDP also mentions the installation of pedestrian-oriented street lighting, and the possibility of placing overhead wires underground.

Richmond Road/Westboro Transportation Management Plan

Boundaries: Ottawa River, Island Park Dr, Byron Ave, Ottawa River Parkway Extension
Transportation Projects: Making Transit More Accessible, Improve Sidewalks, Bike Lanes

The purpose of this plan is to promote a shift to more sustainable modes of transportation in the Richmond Road/Westboro community over the next 15 years. The peak period auto modal share must decrease by 13% to avoid the need for additional roadway capacity. This plan includes designating bike lanes, sidewalk improvement projects, and making public transit more accessible.

1

Riverside South CDP

Boundaries: Ottawa Macdonald-Cartier International Airport, Rideau River
Transportation Projects: Rapid Transit Corridor + Stations

The northwest portion of the site is currently developed as a residential subdivision, and the CDP focuses on the surrounding area east of the river. This plan involves development of a rapid transit corridor, residential areas and an employment area. The subdivision will be expanded to include a variety of uses and housing types.

Scott Street CDP

Boundaries: Northwestern Ave, Bayview Rd, West Wellington St, North of Burnside Ave
Transportation Projects: Confederation LRT to Tunney's Pasture, Extend Sir Frederick Banting north to connect to Sir John A. Macdonald Parkway, Extend Goldenrod Driveway

This CDP is intended to guide future change in the area surrounding the Tunney's Pasture Transit Station. This involves 4 established neighbourhoods: Mechanicsville, Hintonburg, Wellington Village and Champlain Park. Development will include commercial uses, residential uses, institutional and cultural uses. Apartment neighbourhoods will be expanded. The CDP acknowledges that there is an existing hydro substation on Scott Street, and there are no changes proposed for the zoning of these sites.

South Nepean Town Centre CDP

Boundaries: Strandherd Dr, Jock River
Transportation Projects: 2 Rapid Transit Routes, LRT & BRT Alignments

The Town Centre is intended to be a compact, mixed-use, walkable, pedestrian-scaled, and transit-supportive community. It will include a shopping district, retail, office and residential uses.

St. Joseph Boulevard Corridor Study

Boundaries: Montreal Rd in Vanier, Rideau in downtown Ottawa, Wellington St in front of Parliament
Transportation Projects: ---

St. Joseph Boulevard is one of the City's major arterial roads, and is classified as a commercial strip. The purpose of this study is to create a lively, vibrant and diverse district with a mix of places to live, work, shop and play. The study area is divided into 4 basic districts: industrial, neighbourhood commercial, main street, and residential hinterland. Development will involve industrial uses, commercial, office and community uses. There will also be more residential uses, retail uses and government facilities. The Study mentions that there are overhead utility poles along St. Joseph Boulevard and both sides of the street, as well as crossing the road. The City currently has no plans to bury the utility lines, but sees underground hydro service as a long term goal.

1

Uptown Rideau CDP

Boundaries: Rideau St (between King Edward Ave, Cummings Bridge)
Transportation Projects: Sidewalk Widening (eliminate OH hydro plant)

There are currently a mix of retail/office uses and retail/residential uses along the street. The goal is to transform the street into a green, pedestrian streetscape of the highest quality in a compact urban setting, framed with 3-6 storey buildings on both sides of the street. The mainstreet will serve a mix of residential, commercial, institutional, and entertainment functions. The community would like the hydro poles and overhead wires to be removed, as a first priority. This should be done in conjunction with street reconstruction.

Transit-Oriented Development (TOD) Plans

Ottawa's Light Rail Transit (LRT) project runs east-west from Tunney's Pasture in the west to Blair Road in the east. The LRT system includes 12.5 km of new rail, 13 stations and a tunnel through the downtown core. Ten of the stations are a conversion or reconstruction of existing bus rapid transit stations to accommodate light rail and the other three stations are new underground stations in the downtown area. The final design phase and construction will be undertaken over the next few years with system opening day scheduled for 2018.

In anticipation of land development pressure in proximity to the LRT stations, City Council has established priority areas for the creation of transit-oriented development (TOD) plans. The TOD plans set the stage for future transit-supportive, or "intensified", land development by adding in appropriate locations opportunities for additional land use types and densities. The first three TOD studies for land surrounding the "Train", "St. Laurent" and "Cyrville" future LRT stations were approved by City Council on November 14, 2012.

The following concerning Hydro Services is noted:
The main findings and recommended upgrades are as follows:

- *Substation spare capacity is currently limited, especially at Overbrook, Russell, and Moulton.*
- *Overbrook, Russell, and Moulton are already planned to be enlarged by Hydro-Ottawa.*
- *Circuit capacity will have to be upgraded by addition of new lines, especially Russell, and to a lesser extent, Riverdale and Moulton.*

Assuming a slightly lower build-out rate of 25% of eventual build-out within 20 years, the Hydro Ottawa substation build-out plans are not significantly altered. It may only delay the trigger points where additional circuit capacity must be added for development loading. Most of the developer related circuit build-out costs are triggered within the first 10 years using initially proposed build-out rates plans.

1

Village of Richmond CDP

Boundaries: South of Kanata on either side of Jock River
Transportation Plans: Sidewalk Widening

This CDP involves redeveloping the shopping centre in the village, new residential buildings and possibly small commercial buildings. The plan mentions moving buildings closer to the street while adhering to overhead setbacks. The plan seems to be more visually oriented, rather than large expansion.

Wellington Street West CDP

Boundaries: Wellington St (Holland Ave, Parkdale Ave, Spencer St)
Transportation Plans: Road Reconstruction Project (surface and sub-surface infrastructure)

This CDP contains the following goals: to enhance the existing mix of land uses, to establish a clear network of people spaces, to strengthen the traditional built form and spaces through respect and innovation, to capture the opportunities of mainstreet gateways and nodes, to encourage views and vistas, to link the varied character areas together as a unified corridor, and to promote a pedestrian and transit friendly environment. The plan involves adding more residential and commercial uses.

1

ASSETS – PROPERTY PLANT AND EQUIPMENT CONTINUITY SCHEDULE

The tables in this exhibit provides Gross Assets continuity schedules by function for years from 2012 (last rebasing year) through to 2020 as presented in Hydro Ottawa Limited's ("Hydro Ottawa") Electricity Distribution Rate Application for 2016 (EB-2015-0004) based the Ontario Energy Boards minimum reporting groups. Exhibit D-3-1 (updated) provides continuity schedules for amortization and Appendix 2-B, Fixed Asset Continuity Schedules by Uniform System of Account ("USofA") for 2012 to ~~2013~~ 2014 Actuals and ~~2014 Forecast together with~~ budgets for 2015 to 2020.

Hydro Ottawa's 2012 rate application was submitted under Modified International Financial Reporting Standards ("MIFRS") with a transition date of January 1, 2011 as directed by Ontario Energy Board (the "Board"). International Financial Reporting Standards ("IFRS") at that time did not contain standard governing rate-regulated activities. In May 2012, the International Accounting Standards Board ("IASB") decided to develop a project on Rate-regulated Activities. With this pending, the Canadian Accounting Standards Board allowed qualifying Rate Regulated entities to defer the adoption of IFRS to January 1, 2015. Hydro Ottawa Limited elected to take this deferral for financial reporting purposes while continuing to maintain MIFRS for regulatory purposes. The IASB has since issued interim standard *IFRS 14 - Regulatory Deferred Accounts* ("IFRS 14") which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices.

Due to the divergence of financial accounting standards for regulatory reporting and financial reporting purposes, Hydro Ottawa was required to maintain two sets of records for a period of time. Hydro Ottawa has made a one-time adjustment to the 2014 opening Gross Asset Net book value reported under MIFRS to align the two sets of records to avoid future administrative burden of maintaining two sets as well as enhance operational efficiency and reduce the burden on Hydro Ottawa's IT systems. This results in a Net Book Value increase of $502k under MIFRS to be depreciated over the applicable remaining useful lives as well as $195k increase under MIFRS to the cost of

Construction in progress. For fiscal year 2011, Hydro Ottawa had recorded different amount of overheads applied to capital projects and different depreciation amount under MIFRS and CGAAP. The one-time adjustment for rate-making purposes will result in a minor increase to rate base. Hydro Ottawa expects that any rate impact arising from the rate base increase will be offset by savings realized from eliminating duplicate sets of records. The other adjustment was to clear the accumulated depreciation and contributed capital balances to nil as seen in Table 3, column B below. The adjustment can be seen in detail in 2015 Filing Requirements Chapter 2 Appendices (App.2-BA_FA Cont 2014)(updated). With the adoption of IFRS and early adoption of IFRS 14 as the accounting basis for financial reporting purposes on January 1, 2015, Hydro Ottawa's regulatory and financial reporting records are now aligned from an accounting standards basis. All table figures in this exhibit are presented in dollars.

Table 1: 2012 Fixed Assets

	2011 CIP (A)	2011 Ending Balance (B)	2012 Capital Expenditures (C)	2012 CIP (D)	2012 Disposals (E)	2012 Ending Balance =A+B+C-D+E
Land and Buildings	3,576,783	24,553,799	11,628,182	14,139,937	0	25,618,827
TS Primary Above 50	14,544,602	55,223,256	7,592,761	14,060,864	0	63,299,755
DS	7,908,381	44,563,372	8,824,014	10,065,470	0	51,230,296
Poles, Wires	5,181,591	235,652,383	45,139,204	13,209,864	(301,184)	272,462,130
Line Transformers	1,713,616	45,853,921	10,646,715	2,633,883	(204,591)	55,375,779
Services and Meters[1]	643,739	97,432,759	6,622,396	491,858	(35,554)	104,171,482
General Plant	490	36,118,077	248,836	8,386	0	36,359,018
Equipment	1,062,699	15,332,946	3,652,381	1,277,112	(5,545)	18,765,370
IT Assets	3,684,878	28,000,238	14,296,060	13,742,512	0	32,238,664
Other Distribution Assets	101,607	9,602,369	1,654,013	1,375,071	0	9,982,919
Gross Assets	**38,418,389**	**592,333,121**	**110,304,563**	**71,004,956**	**(546,874)**	**669,504,239**
Contributions and Grants	(5,484,667)	(21,049,858)	(23,539,871)	(6,833,595)	0	(43,240,801)
Amortization	0	(36,818,456)	(38,595,334)	0	44,281	(75,369,509)
Total	**32,933,722**	**534,464,807**	**48,169,358**	**64,171,361**	**(502,593)**	**550,893,929**

[1] Stranded Meters have been included here.

Table 2: 2013 Fixed Assets

	2012 CIP (A)	2012 Ending Balance (B)	2013 Capital Expenditures (C)	2013 CIP (D)	2013 Disposals (E)	2013 Ending Balance =A+B+C-D+E
Land and Buildings	14,139,937	25,618,827	13,965,050	279,187	0	53,444,628
TS Primary Above 50	14,060,864	63,299,755	10,658,729	9,678,617	0	78,340,731
DS	10,065,470	51,230,296	10,441,901	8,175,357	(819,212)	62,743,098
Poles, Wires	13,209,864	272,462,130	55,417,921	18,442,036	(1,450,262)	321,197,617
Line Transformers	2,633,883	55,375,779	9,794,504	2,454,063	(195,123)	65,154,980
Services and Meters[2]	491,858	104,171,482	6,136,798	761,454	(1,475,007)	108,563,678
General Plant	8,386	36,359,018	236,223	49,143	0	36,554,484
Equipment	1,277,112	18,765,370	4,015,745	1,979,775	(1,171)	22,077,281
IT Assets	13,742,512	32,238,664	16,764,643	26,671,494	0	36,074,324
Other Distribution Assets	1,375,071	9,982,919	6,643,713	7,323,201	0	10,678,502
Gross Assets	**71,004,956**	**669,504,239**	**134,075,229**	**75,814,327**	**(3,940,774)**	**794,829,323**
Contributions and Grants	(6,833,595)	(43,240,801)	(25,115,208)	(10,530,225)		(64,659,379)
Amortization	0	(75,369,509)	(39,798,292)	0	1,138,182	(114,029,619)
Total	**64,171,361**	**550,893,929**	**69,161,728**	**65,284,102**	**(2,802,592)**	**616,140,325**

[2] Stranded Meters have been included here.

Table 3: 2014 Fixed Assets

	2013 CIP[3] (A)	2013 Ending Balance[4] (B)	Forecast 2014 Capital Expenditures (C)	Actual 2014 Capital Expenditures (C)	Forecast 2014 CIP (D)	Actual 2014 CIP (D)	Forecast 2014 Disposals (E)	Actual 2014 Disposals (E)	Forecast 2014 Ending Balance =A+B+C-D+E	Actual 2014 Ending Balance =A+B+C-D+E
Land and Buildings	279,187	51,869,022	1,885,295	1,085,861	694,548	309,807	0	0	53,338,956	52,924,262
TS Primary Above 50	9,687,975	72,854,689	3,745,236	3,811,919	8,420,960	2,203,105	(2,870)	(2,870)	77,864,068	84,148,606
DS	8,189,580	54,066,400	14,715,828	13,102,124	14,596,902	11,402,191	(138,213)	(167,602)	62,236,694	63,788,312
Poles, Wires	18,472,443	252,125,738	61,706,774	63,977,114	26,153,771	25,838,548	(1,173,116)	(1,403,267)	304,978,068	307,333,480
Line Transformers	2,454,993	45,656,713	9,844,036	8,020,658	2,971,807	1,798,379	(124,321)	(211,115)	54,859,614	54,122,870
Services and Meters	739,788	75,121,923	6,022,160	5,584,972	634,008	50,325	(154,156)	(3,341,030)	81,095,707	78,055,328
General Plant	65,979	31,300,071	524,336	395,733	56,698	0	(1,531)	(1,531)	31,832,157	31,760,252
Equipment	1,977,593	15,099,294	1,934,910	2,004,051	359,156	637,483	(51,686)	(51,686)	18,600,955	18,391,768
IT Assets	26,818,276	10,397,474	12,765,875	12,144,706	2,076,697	4,214,916	(91,791)	(91,791)	47,813,136	45,053,749
Other Distribution Assets	7,324,079	8,151,484	16,925,227	18,123,542	15,999,272	24,322,365	(4,483)	(4,483)	16,397,035	9,272,257
Gross Assets	**76,009,893**	**616,642,806**	**130,069,675**	**128,250,681**	**71,963,817**	**70,777,120**	**(1,742,167)**	**(5,275,374)**	**749,016,390**	**744,850,885**
Contributions and Grants	(10,530,225)	0	(22,405,563)	(22,930,582)	(12,792,224)	(9,836,162)			(20,143,565)	(23,624,645)
Amortization	0	0	(36,517,006)	(35,923,023)			597,688	2,562,263	(35,919,318)	(33,360,760)
Total	**65,479,667**	**616,642,806**	**71,147,106**	**69,397,075**	**59,171,593**	**60,940,957**	**(1,144,479)**	**(2,713,111)**	**692,953,507**	**687,865,481**

[3] As described above CIP includes one-time increase to opening values of $195k
[4] As described above Property, plant and equipment includes one-time adjustment to opening cost of $502k, as well, opening Gross Asset values includes opening Amortization of $114,030k as required for the transition to IFRS

Table 4: 2015 Fixed Assets

Balances Reflect 2014 Forecast

	2014 CIP (A)	2014 Ending Balance (B)	2015 Capital Expenditures (C)	2015 CIP (D)	2015 Disposals (E)	2015 Ending Balance =A+B+C-D+E
Land and Buildings	694,548	53,338,956	2,313,153	1,136,081	0	55,210,576
TS Primary Above 50	8,420,960	77,864,068	1,646,063	911,635	0	87,019,457
DS	14,596,902	62,236,694	14,663,513	14,378,881	(153,346)	76,964,881
Poles, Wires	26,153,771	304,978,068	56,152,253	26,545,963	(1,199,260)	359,538,869
Line Transformers	2,971,807	54,859,614	12,439,831	2,937,729	(211,886)	67,121,637
Services and Meters	634,008	81,095,707	7,748,188	630,413	(150,377)	88,697,113
General Plant	56,698	31,832,157	492,174	56,620	0	32,324,409
Equipment	359,156	18,600,955	4,311,606	2,183,285	(48,184)	21,040,248
IT Assets	2,076,697	47,813,136	11,517,399	4,001,808	0	57,405,424
Other Distribution Assets	15,999,272	16,397,035	2,799,240	932,559	0	34,262,988
Gross Assets	**71,963,817**	**749,016,390**	**114,083,420**	**53,714,972**	**(1,763,053)**	**879,585,602**
Contributions and Grants	(12,792,224)	(20,143,565)	(25,432,188)	(12,792,224)		(45,575,753)
Amortization	0	(35,919,318)	(38,557,773)		1,013,053	(73,464,038)
Total	**59,171,593**	**692,953,507**	**50,093,459**	**40,922,748**	**(750,000)**	**760,545,811**

[5]

[5] Tables with title "Balances reflect 2014 Forecast". Numbers in table were incorporated into proposed rates for 2016 to 2020. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Balances Reflect 2014 Actuals

	2014 CIP (A)	2014 Ending Balance (B)	2015 Capital Expenditures (C)	2015 CIP (D)	2015 Disposals (E)	2015 Ending Balance =A+B+C-D+E
Land and Buildings	309,807	52,924,262	2,396,059	834,247	0	54,795,882
TS Primary Above 50	2,203,105	84,148,606	7,802,802	850,518	0	93,303,995
DS	11,402,191	63,788,312	14,727,930	11,248,587	(153,346)	78,516,499
Poles, Wires	25,838,548	307,333,480	56,170,838	26,249,326	(1,199,260)	361,894,281
Line Transformers	1,798,379	54,122,870	12,479,811	1,804,281	(211,886)	66,384,893
Services and Meters	50,325	78,055,328	7,748,201	46,743	(150,377)	85,656,734
General Plant	0	31,760,252	492,321	69	0	32,252,504
Equipment	637,483	18,391,768	4,311,695	2,461,701	(48,184)	20,831,061
IT Assets	4,214,916	45,053,749	9,317,399	3,940,027	0	54,646,037
Other Distribution Assets	24,322,365	9,272,257	(4,042,588)	2,413,824	0	27,138,210
Gross Assets	**70,777,120**	**744,850,885**	**111,404,467**	**49,849,322**	**(1,763,053)**	**875,420,097**
Contributions and Grants	(9,836,162)	(23,624,645)	(25,432,188)	(13,394,060)		(45,498,935)
Amortization	0	(33,360,760)	(38,416,273)		1,013,053	(70,763,980)
Total	**60,940,957**	**687,865,481**	**47,556,006**	**36,455,262**	**(750,000)**	**759,157,182**

[6]

[6] Tables with title "Balances reflect 2014 Actuals". Numbers in table are for information purposes only. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Table 5: 2016 Fixed Assets

Balances Reflect 2014 Forecast

	2015 CIP (A)	2015 Ending Balance (B)	2016 Capital Expenditures (C)	2016 CIP (D)	2016 Disposals (E)	2016 Ending Balance =A+B+C-D+E
Land and Buildings	1,136,081	55,210,576	2,313,110	1,468,702	0	57,191,065
TS Primary Above 50	911,635	87,019,457	1,634,612	2,044,213	0	87,521,491
DS	14,378,881	76,964,881	13,989,440	13,507,027	(153,346)	91,672,829
Poles, Wires	26,545,963	359,538,869	60,605,090	29,657,564	(1,199,260)	415,833,098
Line Transformers	2,937,729	67,121,637	10,588,683	2,937,667	(211,886)	77,498,496
Services and Meters	630,413	88,697,113	7,719,934	630,022	(150,377)	96,267,061
General Plant	56,620	32,324,409	1,249,580	56,506	0	33,574,103
Equipment	2,183,285	21,040,248	3,638,034	413,172	(48,184)	26,400,211
IT Assets	4,001,808	57,405,424	15,399,551	10,587,576	0	66,219,207
Other Distribution Assets	932,559	34,262,988	5,096,070	563,641	0	39,727,976
Gross Assets	**53,714,972**	**879,585,602**	**122,234,104**	**61,866,088**	**(1,763,053)**	**991,905,537**
Contributions and Grants	(12,792,224)	(45,575,753)	(25,701,824)	(12,792,224)		(71,277,577)
Amortization	0	(73,464,038)	(40,826,114)		1,013,053	(113,277,099)
Total	**40,922,748**	**760,545,811**	**55,706,166**	**49,073,864**	**(750,000)**	**807,350,861**

[7]

[7] Tables with title "Balances reflect 2014 Forecast". Numbers in table were incorporated into proposed rates for 2016 to 2020. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Balances Reflect 2014 Actuals

	2015 CIP (A)	2015 Ending Balance (B)	2016 Capital Expenditures (C)	2016 CIP (D)	2016 Disposals (E)	2016 Ending Balance =A+B+C-D+E
Land and Buildings	834,247	54,795,882	2,313,110	1,166,868	0	56,776,371
TS Primary Above 50	850,518	93,303,995	1,634,612	1,983,096	0	93,806,029
DS	11,248,587	78,516,499	13,989,440	10,376,733	(153,346)	93,224,447
Poles, Wires	26,249,326	361,894,281	60,605,090	29,360,927	(1,199,260)	418,188,510
Line Transformers	1,804,281	66,384,893	10,588,683	1,804,219	(211,886)	76,761,752
Services and Meters	46,743	85,656,734	7,719,934	46,352	(150,377)	93,226,682
General Plant	69	32,252,504	1,249,580	(45)	0	33,502,198
Equipment	2,461,701	20,831,061	3,638,034	691,588	(48,184)	26,191,024
IT Assets	3,940,027	54,646,037	15,399,551	10,525,795	0	63,459,820
Other Distribution Assets	2,413,824	27,138,210	5,096,070	2,044,906	0	32,603,198
Gross Assets	**49,849,322**	**875,420,097**	**122,234,104**	**58,000,438**	**(1,763,053)**	**987,740,032**
Contributions and Grants	(13,394,060)	(45,498,935)	(25,701,824)	(13,394,060)		(71,200,759)
Amortization	0	(70,763,980)	(40,755,585)		1,013,053	(110,506,512)
Total	**36,455,262**	**759,157,182**	**55,776,695**	**44,606,378**	**(750,000)**	**806,032,761**

[8]

[8] Tables with title "Balances reflect 2014 Actuals". Numbers in table are for information purposes only. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Table 6: 2017 Fixed Assets

Balances Reflect 2014 Forecast

	2016 CIP (A)	2016 Ending Balance (B)	2017 Capital Expenditures (C)	2017 CIP (D)	2017 Disposals (E)	2017 Ending Balance =A+B+C-D+E
Land and Buildings	1,468,702	57,191,065	4,530,791	3,803,818	0	59,386,740
TS Primary Above 50	2,044,213	87,521,491	9,831,305	8,605,201	0	90,791,808
DS	13,507,027	91,672,829	12,147,266	18,373,287	(153,346)	98,800,489
Poles, Wires	29,657,564	415,833,098	50,611,803	28,352,883	(1,199,260)	466,550,322
Line Transformers	2,937,667	77,498,496	11,309,359	2,978,335	(211,886)	88,555,301
Services and Meters	630,022	96,267,061	8,682,455	632,273	(150,377)	104,796,888
General Plant	56,506	33,574,103	434,236	56,430	0	34,008,415
Equipment	413,172	26,400,211	6,177,699	359,223	(48,184)	32,583,675
IT Assets	10,587,576	66,219,207	7,039,945	2,182,831	0	81,663,897
Other Distribution Assets	563,641	39,727,976	5,587,269	688,323	0	45,190,563
Gross Assets	**61,866,088**	**991,905,537**	**116,352,128**	**66,032,602**	**(1,763,053)**	**1,102,328,098**
Contributions and Grants	(12,792,224)	(71,277,577)	(25,296,257)	(12,792,224)		(96,573,834)
Amortization	0	(113,277,099)	(44,145,078)		1,013,053	(156,409,124)
Total	**49,073,864**	**807,350,861**	**46,910,793**	**53,240,378**	**(750,000)**	**849,345,140**

[9]

[9] Tables with title "Balances reflect 2014 Forecast". Numbers in table were incorporated into proposed rates for 2016 to 2020. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Balance Reflect 2014 Actuals

	2016 CIP (A)	2016 Ending Balance (B)	2017 Capital Expenditures (C)	2017 CIP (D)	2017 Disposals (E)	2017 Ending Balance =A+B+C-D+E
Land and Buildings	1,166,868	56,776,371	4,530,791	3,501,984	0	58,972,046
TS Primary Above 50	1,983,096	93,806,029	9,831,305	8,544,084	0	97,076,346
DS	10,376,733	93,224,447	12,147,266	15,242,993	(153,346)	100,352,107
Poles, Wires	29,360,927	418,188,510	50,611,803	28,056,246	(1,199,260)	468,905,734
Line Transformers	1,804,219	76,761,752	11,309,359	1,844,887	(211,886)	87,818,557
Services and Meters	46,352	93,226,682	8,682,455	48,603	(150,377)	101,756,509
General Plant	(45)	33,502,198	434,236	(121)	0	33,936,510
Equipment	691,588	26,191,024	6,177,699	637,639	(48,184)	32,374,488
IT Assets	10,525,795	63,459,820	7,039,945	2,121,050	0	78,904,510
Other Distribution Assets	2,044,906	32,603,198	5,587,269	2,169,588	0	38,065,785
Gross Assets	**58,000,438**	**987,740,032**	**116,352,128**	**62,166,952**	**(1,763,053)**	**1,098,162,593**
Contributions and Grants	(13,394,060)	(71,200,759)	(25,296,257)	(13,394,060)		(96,497,016)
Amortization	0	(110,506,512)	(44,057,757)		1,013,053	(153,551,216)
Total	**44,606,378**	**806,032,761**	**46,998,114**	**48,772,892**	**(750,000)**	**848,114,361**

[10]

[10] Tables with title "Balances reflect 2014 Actuals". Numbers in table are for information purposes only. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Table 7: 2018 Fixed Assets

Balance Reflect 2014 Forecasts

	2017 CIP (A)	2017 Ending Balance (B)	2018 Capital Expenditures (C)	2018 CIP (D)	2018 Disposals (E)	2018 Ending Balance =A+B+C-D+E
Land and Buildings	3,803,818	59,386,740	3,818,909	4,667,976	0	62,341,491
TS Primary Above 50	8,605,201	90,791,808	6,978,261	13,502,607	0	92,872,663
DS	18,373,287	98,800,489	13,311,307	10,603,595	(153,346)	119,728,142
Poles, Wires	28,352,883	466,550,322	54,246,123	26,662,342	(1,199,260)	521,287,726
Line Transformers	2,978,335	88,555,301	11,767,301	3,000,508	(211,886)	100,088,543
Services and Meters	632,273	104,796,888	8,902,932	631,931	(150,377)	113,549,785
General Plant	56,430	34,008,415	123,299	56,423	0	34,131,721
Equipment	359,223	32,583,675	5,148,673	364,579	(48,184)	37,678,808
IT Assets	2,182,831	81,663,897	5,337,193	2,076,697	0	87,107,224
Other Distribution Assets	688,323	45,190,563	5,610,816	409,931	0	51,079,771
Gross Assets	**66,032,602**	**1,102,328,098**	**115,244,814**	**61,976,587**	**(1,763,053)**	**1,219,865,874**
Contributions and Grants	(12,792,224)	(96,573,834)	(25,075,051)	(12,792,224)		(121,648,885)
Amortization	0	(156,409,124)	(47,047,409)		1,013,053	(202,443,480)
Total	**53,240,378**	**849,345,140**	**43,122,354**	**49,184,363**	**(750,000)**	**895,773,509**

[11]

[11] Tables with title "Balances reflect 2014 Forecast". Numbers in table were incorporated into proposed rates for 2016 to 2020. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Balance Reflect 2014 Actuals

	2017 CIP (A)	2017 Ending Balance (B)	2018 Capital Expenditures (C)	2018 CIP (D)	2018 Disposals (E)	2018 Ending Balance =A+B+C-D+E
Land and Buildings	3,501,984	58,972,046	3,818,909	4,366,142	0	61,926,797
TS Primary Above 50	8,544,084	97,076,346	6,978,261	13,441,490	0	99,157,201
DS	15,242,993	100,352,107	13,311,307	7,473,301	(153,346)	121,279,760
Poles, Wires	28,056,246	468,905,734	54,246,123	26,365,705	(1,199,260)	523,643,138
Line Transformers	1,844,887	87,818,557	11,767,301	1,867,060	(211,886)	99,351,799
Services and Meters	48,603	101,756,509	8,902,932	48,261	(150,377)	110,509,406
General Plant	(121)	33,936,510	123,299	(128)	0	34,059,816
Equipment	637,639	32,374,488	5,148,673	642,995	(48,184)	37,469,621
IT Assets	2,121,050	78,904,510	5,337,193	2,014,916	0	84,347,837
Other Distribution Assets	2,169,588	38,065,785	5,610,816	1,891,196	0	43,954,993
Gross Assets	**62,166,952**	**1,098,162,593**	**115,244,814**	**58,110,937**	**(1,763,053)**	**1,215,700,369**
Contributions and Grants	(13,394,060)	(96,497,016)	(25,075,051)	(13,394,060)		(121,572,067)
Amortization	0	(153,551,216)	(46,943,424)		1,013,053	(199,481,586)
Total	**48,772,892**	**848,114,361**	**43,226,339**	**44,716,877**	**(750,000)**	**894,646,716**

[12]

[12] Tables with title "Balances reflect 2014 Actuals". Numbers in table are for information purposes only. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Table 8: 2019 Fixed Assets

Balance Reflect 2014 Forecasts

	2018 CIP (A)	2018 Ending Balance (B)	2019 Capital Expenditures (C)	2019 CIP (D)	2019 Disposals (E)	2019 Ending Balance =A+B+C-D+E
Land and Buildings	4,667,976	62,341,491	4,595,372	8,516,169	0	63,088,670
TS Primary Above 50	13,502,607	92,872,663	9,332,947	22,539,204	0	93,169,013
DS	10,603,595	119,728,142	14,992,638	19,055,333	(153,346)	126,115,696
Poles, Wires	26,662,342	521,287,726	52,376,147	27,902,678	(1,199,260)	571,224,277
Line Transformers	3,000,508	100,088,543	11,519,979	3,062,596	(211,886)	111,334,548
Services and Meters	631,931	113,549,785	8,968,403	637,459	(150,377)	122,362,283
General Plant	56,423	34,131,721	248,568	56,464	0	34,380,248
Equipment	364,579	37,678,808	4,199,829	373,102	(48,184)	41,821,930
IT Assets	2,076,697	87,107,224	11,341,465	8,192,037	0	92,333,349
Other Distribution Assets	409,931	51,079,771	5,599,500	625,424	0	56,463,778
Gross Assets	**61,976,587**	**1,219,865,874**	**123,174,848**	**90,960,464**	**(1,763,053)**	**1,312,293,792**
Contributions and Grants	(12,792,224)	(121,648,885)	(25,576,549)	(12,792,224)		(147,225,434)
Amortization	0	(202,443,480)	(48,948,694)		1,013,053	(250,379,121)
Total	**49,184,363**	**895,773,509**	**48,649,605**	**78,168,240**	**(750,000)**	**914,689,237**

[13]

[13] Tables with title "Balances reflect 2014 Forecast". Numbers in table were incorporated into proposed rates for 2016 to 2020. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Balance Reflect 2014 Actuals

	2018 CIP (A)	2018 Ending Balance (B)	2019 Capital Expenditures (C)	2019 CIP (D)	2019 Disposals (E)	2019 Ending Balance =A+B+C-D+E
Land and Buildings	4,366,142	61,926,797	4,595,372	8,214,335	0	62,673,976
TS Primary Above 50	13,441,490	99,157,201	9,332,947	22,478,087	0	99,453,551
DS	7,473,301	121,279,760	14,992,638	15,925,039	(153,346)	127,667,314
Poles, Wires	26,365,705	523,643,138	52,376,147	27,606,041	(1,199,260)	573,579,689
Line Transformers	1,867,060	99,351,799	11,519,979	1,929,148	(211,886)	110,597,804
Services and Meters	48,261	110,509,406	8,968,403	53,789	(150,377)	119,321,904
General Plant	(128)	34,059,816	248,568	(87)	0	34,308,343
Equipment	642,995	37,469,621	4,199,829	651,518	(48,184)	41,612,743
IT Assets	2,014,916	84,347,837	11,341,465	8,130,256	0	89,573,962
Other Distribution Assets	1,891,196	43,954,993	5,599,500	2,106,689	0	49,339,000
Gross Assets	**58,110,937**	**1,215,700,369**	**123,174,848**	**87,094,814**	**(1,763,053)**	**1,308,128,287**
Contributions and Grants	(13,394,060)	(121,572,067)	(25,576,549)	(13,394,060)		(147,148,616)
Amortization	0	(199,481,586)	(48,823,718)		1,013,053	(247,292,251)
Total	**44,716,877**	**894,646,716**	**48,774,581**	**73,700,754**	**(750,000)**	**913,687,420**

[14]

[14] Tables with title "Balances reflect 2014 Actuals". Numbers in table are for information purposes only. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Table 9: 2020 Fixed Assets

Balance Reflect 2014 Forecasts

	2019 CIP (A)	2019 Ending Balance (B)	2020 Capital Expenditures (C)	2020 CIP (D)	2020 Disposals (E)	2020 Ending Balance =A+B+C-D+E
Land and Buildings	8,516,169	63,088,670	4,887,979	6,199,103	0	70,293,715
TS Primary Above 50	22,539,204	93,169,013	10,017,547	13,145,810	0	112,579,954
DS	19,055,333	126,115,696	14,471,223	18,656,033	(153,346)	140,832,873
Poles, Wires	27,902,678	571,224,277	53,841,724	28,106,289	(1,199,260)	623,663,130
Line Transformers	3,062,596	111,334,548	11,821,423	3,031,585	(211,886)	122,975,096
Services and Meters	637,459	122,362,283	9,170,797	640,537	(150,377)	131,379,625
General Plant	56,464	34,380,248	177	56,509	0	34,380,380
Equipment	373,102	41,821,930	5,712,584	359,495	(48,184)	47,499,937
IT Assets	8,192,037	92,333,349	6,253,080	2,127,237	0	104,651,229
Other Distribution Assets	625,424	56,463,778	5,598,278	662,677	0	62,024,803
Gross Assets	**90,960,464**	**1,312,293,792**	**121,774,812**	**72,985,273**	**(1,763,053)**	**1,450,280,742**
Contributions and Grants	(12,792,224)	(147,225,434)	(26,088,080)	(12,792,224)		(173,313,514)
Amortization	0	(250,379,121)	(50,294,804)		1,013,053	(299,660,872)
Total	**78,168,240**	**914,689,237**	**45,391,928**	**60,193,049**	**(750,000)**	**977,306,356**

15

[15] Tables with title "Balances reflect 2014 Forecast". Numbers in table were incorporated into proposed rates for 2016 to 2020. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

Balance Reflect 2014 Actuals

	2019 CIP (A)	2019 Ending Balance (B)	2020 Capital Expenditures (C)	2020 CIP (D)	2020 Disposals (E)	2020 Ending Balance =A+B+C-D+E
Land and Buildings	8,214,335	62,673,976	4,887,979	5,897,269	0	69,879,021
TS Primary Above 50	22,478,087	99,453,551	10,017,547	13,084,693	0	118,864,492
DS	15,925,039	127,667,314	14,471,223	15,525,739	(153,346)	142,384,491
Poles, Wires	27,606,041	573,579,689	53,841,724	27,809,652	(1,199,260)	626,018,542
Line Transformers	1,929,148	110,597,804	11,821,423	1,898,137	(211,886)	122,238,352
Services and Meters	53,789	119,321,904	9,170,797	56,867	(150,377)	128,339,246
General Plant	(87)	34,308,343	177	(42)	0	34,308,475
Equipment	651,518	41,612,743	5,712,584	637,911	(48,184)	47,290,750
IT Assets	8,130,256	89,573,962	6,253,080	2,065,456	0	101,891,842
Other Distribution Assets	2,106,689	49,339,000	5,598,278	2,143,942	0	54,900,025
Gross Assets	**87,094,814**	**1,308,128,287**	**121,774,812**	**69,119,623**	**(1,763,053)**	**1,446,115,237**
Contributions and Grants	(13,394,060)	(147,148,616)	(26,088,080)	(13,394,060)		(173,236,696)
Amortization	0	(247,292,251)	(50,160,773)		1,013,053	(296,439,971)
Total	**73,700,754**	**913,687,420**	**45,525,959**	**55,725,563**	**(750,000)**	**976,438,570**

[16]

[16] Tables with title "Balances reflect 2014 Actuals". Numbers in table are for information purposes only. Rates for 2016 to 2020 will be updated once the OEB release the 2016 models.

VARIANCE ANALYSIS ON GROSS ASSETS

Table 10 below shows Hydro Ottawa's gross asset additions. Refer to Appendix 2-BA Fixed Asset Continuity Schedule, gross assets additions are the sum of additions and disposals before depreciation and capital contributions. Table 11 below shows the Gross Asset year-over-year variance. The variance analysis is provided below the tables.

Table 10: Gross Asset Additions

$000s	2012 Approved	2012 Actual	2013 Actual	2014 Forecast	2014 Actual	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test
Land and Buildings	9,460	1,065	27,826	1,470	1,055	1,872	1,980	2,196	2,955	747	7,205
TS Primary Above 50	662	8,076	15,041	5,009	11,294	9,155	502	3,270	2,081	296	19,411
DS	10,433	6,667	11,513	8,170	9,722	14,728	14,708	7,128	20,928	6,388	14,717
Poles, Wires	34,391	36,810	48,735	52,852	55,208	54,561	56,294	50,717	54,737	49,937	52,439
Line Transformers	8,110	9,522	9,779	9,203	8,466	12,262	10,377	11,057	11,533	11,246	11,641
Services and Meters	11,788	6,739	4,392	5,974	2,933	7,601	7,570	8,530	8,753	8,812	9,017
General Plant	713	241	195	532	460	492	1,250	434	123	249	0
Equipment	3,422	3,432	3,312	3,502	3,292	2,439	5,360	6,183	5,095	4,143	5,678
IT Assets	7,569	4,238	3,836	37,416	34,656	9,592	8,814	15,445	5,443	5,226	12,318
Other Distribution Assets	1,781	381	696	8,246	1,121	17,866	5,465	5,463	5,889	5,384	5,561
Gross Asset Additions	**88,329**	**77,171**	**125,325**	**132,374**	**128,208**	**130,569**	**112,320**	**110,423**	**117,538**	**92,428**	**137,987**

Table 11: Gross Asset Year-over-Year Variance

$000s	12-Approved	13-12	Forecast 14-13	Actual 14-13	Forecast 15-14	Actual 15-14	16-15	17-16	18-17	19-18	20-19
Land and Buildings	(8,395)	26,761	(26,356)	(26,771)	402	816	109	215	759	(2,208)	6,458
TS Primary Above 50	7,414	6,964	(10,032)	(3,747)	4,146	(2,139)	(8,653)	2,768	(1,189)	(1,785)	19,115
DS	(3,766)	4,846	(3,343)	(1,791)	6,558	5,006	(20)	(7,580)	13,800	(14,540)	8,330
Poles, Wires	2,419	11,926	4,117	6,472	1,708	(647)	1,733	(5,577)	4,020	(4,801)	2,502
Line Transformers	1,412	257	(576)	(1,313)	3,059	3,796	(1,885)	680	476	(287)	395
Services and Meters	(5,049)	(2,347)	1,582	(1,459)	1,628	4,668	(31)	960	223	60	205
General Plant	(472)	(45)	337	265	(40)	32	757	(815)	(311)	125	(248)
Equipment	10	(121)	190	(19)	(1,062)	(853)	2,921	824	(1,088)	(952)	1,535
IT Assets	(3,331)	(403)	33,580	30,821	(27,823)	(25,064)	(779)	6,631	(10,001)	(217)	7,092
Other Distribution Assets	(1,400)	315	7,550	425	9,620	16,745	(12,401)	(2)	427	(505)	177
Gross Asset Additions	**(11,158)**	**48,154**	**7,048**	**2,883**	**(1,804)**	**2,361**	**(18,249)**	**(1,897)**	**7,115**	**(25,110)**	**45,559**

2012 Actual vs. 2012 Board Approved Budget:

In comparing the 2012 Actuals with 2012 Board Approved budget, the decrease in gross assets of $11.2 is primarily due to the following programs:

- The purchase of land for the Facilities Implementation Plan was included in the 2012 Board Approved additions. The acquisition started in 2012, but was only completed in 2013.
- The project to construct a new 230kV to 27kV Terry Fox Substation, located in south Kanata, was started in 2009. The building costs were included in the 2012 Board Approved additions; however the actual costs incurred were in 2013.
- Demand capital especially services related were lower than approved in 2012. They are customer demand driven.

2013 Actual vs. 2012 Actual:

The total gross assets additions in 2013 of $125M are an increase of $48M compared with 2012 actuals. This is primarily due to the following programs:

- The purchase of land for two new facilities was started in 2012, but transaction closed in 2013 for a total of $19M.
- The Terry Fox substation was completed in 2013, for a total of $22M including building cost and station equipment.
- Poles and Wires increased from 2012 by $12M, half of it was in Demand capital (residential and new commercial). The other half is in Sustainment, mainly the Cable Replacement Program and the Woodroffe UW 4kV System Voltage Conversion project.

2014 Actual ~~Forecast~~ vs. 2013 Actual:

The total gross assets additions ~~forecasted~~ in 2014 of $128M ~~$132M~~ are an increase of $~~37~~M compared with 2013 actuals. This is primarily an increase in IT assets offset by a decrease in land and buildings:

- IT assets increased by $31M ~~$34M~~, the most notable one was CC&B (Customer Care and Billing) system upgrade. The project started in late 2010, went live in Q1 2014, for a total cost of $26M.
- Land and Buildings decreased due to the completion of Terry Fox substation and the land purchase for the Facilities Implementation Plan in 2013.

Forecast 2015 Bridge Year vs. 2014 Actual~~Forecast~~:

Total forecast gross assets additions in 2015 of $130M are an increase ~~a decrease~~ of ~~$1.8M~~ $2M compared with 2014 Actual ~~Forecast~~. This is primarily due to the timing of project completion.

- IT assets decreased from 2014 due to CC&B completed.

- Increase in Distribution Stations including Stations Transformer Replacement

Forecast 2016 Test Year vs. 2015 Bridge Year:

Total forecast gross assets additions in 2016 of $112M are a decrease of $18M compared with 2015 Bridge Year. This is primarily due to a decrease in the following programs:

- Other distribution assets decreased by $12M primarily explained by the HONI CCRA (Hydro One Connection and Cost Recovery Agreement) payments in 2015 for the Hawthorne and Cyrville stations.
- TS Primary Above 50 decreased by $9M due to the timing of the stations completion. 2015 projected a few large stations completion while the 2016 plan is to focus on the Poles and Wires.

Forecast 2017 Test Year vs. 2016 Test Year:

Total forecast gross assets additions in 2017 of $110M are a decrease of $2M compared with 2016. This is primarily due to the changes in the following programs:

- DS (Station Equipment) decreased by $7M and Poles and Wires decreased by $5M
- IT Assets increased by $6M primarily the JDE application upgrade to be completed in 2017.

Forecast 2018 Test Year vs. 2017 Test Year:

Total forecast gross assets additions in 2018 of $117M are an increase of $7M compared with 2017. This is primarily due to the changes in the following programs:

- DS (Station Equipment) increased by $14M largely explained by an increase in transformer replacement
- IT Assets decreased by $10M due to the completion of JDE upgrade and SCADA replacement in 2017.

Forecast 2019 Test Year vs. 2018 Test Year:

Total forecast gross assets additions in 2019 of $92M are a decrease of $25M compared with 2018. The capital spending is steady, but the completion of some major projects forecasted in 2020, including the following:

- Large multi-year station projects are expected to be ongoing and are planned to be complete in 2020

Forecast 2020 Test Year vs. 2019 Test Year:

Total forecast gross assets additions in 2020 of $138M are an increase of $45M compared with 2019. Several major projects started in previous years to be completed in 2020.

- A number of large multi-year station projects are to be completed in 2020.
- CC&B enhancement of $6M

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2012**

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	23,536,162	2,579,010	0	26,115,172	-7,046,765	-7,661,587	0	(14,708,352)	11,406,820
CEC	1612	Land Rights (Formally known as Account 1906)	1,912,380	10,072	0	1,922,452	-48,471	-48,860	0	(97,331)	1,825,121
N/A	1805	Land	5,308,934	10,336	0	5,319,270	0	0	0	0	5,319,270
47	1808	Buildings	17,332,485	1,044,621	0	18,377,106	-512,979	-544,338	0	(1,057,317)	17,319,788
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	55,223,256	8,076,499	0	63,299,755	-2,107,116	-2,201,965	0	(4,309,081)	58,990,674
47	1820	Distribution Station Equipment <50 kV	44,563,372	6,666,923	0	51,230,296	-3,585,604	-3,696,778	0	(7,282,382)	43,947,914
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	62,485,224	8,911,408	(208,788)	71,187,843	-1,577,766	-1,783,190	8,553	(3,352,403)	67,835,441
47	1835	Overhead Conductors & Devices	48,247,215	8,225,709	0	56,472,924	-1,288,846	-1,500,743	0	(2,789,589)	53,683,335
47	1840	Underground Conduit	58,232,836	7,538,304	0	65,771,140	-1,957,362	-2,158,811	0	(4,116,173)	61,654,967
47	1845	Underground Conductors & Devices	66,687,109	12,435,509	(92,396)	79,030,222	-3,212,798	-3,539,505	19,139	(6,733,164)	72,297,058
47	1850	Line Transformers	45,853,921	9,726,448	(204,591)	55,375,779	-1,710,147	-1,972,606	11,659	(3,671,095)	51,704,684
47	1855	Services (Overhead & Underground)	44,415,222	4,107,838	0	48,523,059	-1,164,837	-1,282,116	0	(2,446,953)	46,076,106
47	1860	Meters	9,568,361	791,230	(448)	10,359,143	-3,103,247	-3,023,692	75	(6,126,864)	4,232,279
47	1860	Meters (Smart Meters)	43,449,176	1,875,209	(35,106)	45,289,279	-3,536,288	-3,672,851	3,113	(7,206,027)	38,083,253
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	36,118,077	240,940	0	36,359,018	-2,130,172	-1,971,214	0	(4,101,386)	32,257,632
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (10 years)	1,705,904	111,455	0	1,817,358	-289,721	-293,141	0	(582,862)	1,234,497
8	1915	Office Furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0
10	1920	Computer Equipment - Hardware	4,101,696	1,414,660	0	5,516,356	-1,307,319	-1,290,258	0	(2,597,577)	2,918,779
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	362,379	244,757	0	607,136	-65,889	-111,743	0	(177,632)	429,504
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	8,101,699	1,983,051	(5,545)	10,079,205	-683,800	-860,990	1,743	(1,543,046)	8,536,159
8	1935	Stores Equipment	583,608	0	0	583,608	-89,316	-55,621	0	(144,937)	438,671
8	1940	Tools, Shop & Garage Equipment	3,982,761	484,698	0	4,467,458	-631,988	-662,651	0	(1,294,639)	3,172,820
8	1945	Measurement & Testing Equipment	136,418	129,903	0	266,321	-43,351	-43,628	0	(86,980)	179,341
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	583,218	710,515	0	1,293,734	-148,445	-194,445	0	(342,889)	950,844
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	239,338	18,348	0	257,686	-24,568	-28,710	0	(53,278)	204,408
47	1970	Load Management Controls Customer Premises	291,630	(93)	0	291,538	-52,415	-52,554	0	(104,969)	186,569
47	1975	Load Management Controls Utility Premises	39,548	0	0	39,548	-7,189	-7,208	0	(14,397)	25,151
47	1980	System Supervisor Equipment	7,165,092	380,643	0	7,545,735	-715,365	-740,020	0	(1,455,385)	6,090,349
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	0	0	0	0	0	0	0	0	0
47	2440	Deferred Revenue5	(21,049,858)	(22,190,943)	0	(43,240,801)	276,872	857,607	0	1,134,479	(42,106,323)
	1609	Capital Contributions Paid	2,106,099	0	0	2,106,099	-53,567	-53,713	0	(107,280)	1,998,820
		Sub-Total	**$571,283,263**	**$55,527,050**	**($546,874)**	**$626,263,438**	**($36,818,456)**	**($38,595,334)**	**$44,281**	**($75,369,509)**	**$550,893,929**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$0				$0	$0
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$0				$0	$0
		Total PP&E	**$571,283,263**	**$55,527,050**	**($546,874)**	**$626,263,438**	**($36,818,456)**	**($38,595,334)**	**$44,281**	**($75,369,509)**	**$550,893,929**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**($38,595,334)**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation **($38,595,334)**

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2013

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	26,115,172	2,144,980	0	28,260,152	(14,708,352)	(7,809,802)	0	(22,518,154)	5,741,998
CEC	1612	Land Rights (Formally known as Account 1906)	1,922,452	1,840	0	1,924,292	(97,331)	(48,764)	0	(146,095)	1,778,196
N/A	1805	Land	5,319,270	19,613,594	0	24,932,864	0	0	0	0	24,932,864
47	1808	Buildings	18,377,106	8,210,367	0	26,587,472	(1,057,317)	(671,998)	0	(1,729,315)	24,858,157
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	63,299,755	15,040,976	0	78,340,731	(4,309,081)	(2,328,032)	0	(6,637,114)	71,703,617
47	1820	Distribution Station Equipment <50 kV	51,230,296	12,332,014	(819,212)	62,743,098	(7,282,382)	(3,634,358)	644,120	(10,272,620)	52,470,478
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	71,187,843	9,567,350	(166,289)	80,588,905	(3,352,403)	(1,979,636)	11,415	(5,320,624)	75,268,282
47	1835	Overhead Conductors & Devices	56,472,924	11,676,072	(248,901)	67,900,095	(2,789,589)	(1,716,864)	45,607	(4,460,846)	63,439,249
47	1840	Underground Conduit	65,771,140	14,463,486	0	80,234,625	(4,116,173)	(2,428,122)	0	(6,544,295)	73,690,330
47	1845	Underground Conductors & Devices	79,030,222	14,478,842	(1,035,072)	92,473,992	(6,733,164)	(3,875,609)	125,088	(10,483,685)	81,990,307
47	1850	Line Transformers	55,375,779	9,974,324	(195,123)	65,154,980	(3,671,095)	(2,241,043)	22,556	(5,889,582)	59,265,398
47	1855	Services (Overhead & Underground)	48,523,059	3,557,667	0	52,080,726	(2,446,953)	(1,364,057)	0	(3,811,010)	48,269,716
47	1860	Meters	10,359,143	500,011	0	10,859,155	(6,126,864)	(3,053,947)	0	(9,180,811)	1,678,344
47	1860	Meters (Smart Meters)	45,289,279	1,809,525	(1,475,007)	45,623,797	(7,206,027)	(3,700,832)	289,396	(10,617,462)	35,006,334
N/A	1905	Land	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	36,359,018	195,467	0	36,554,484	(4,101,386)	(1,879,581)	0	(5,980,967)	30,573,518
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (10 years)	1,817,358	163,426	0	1,980,784	(582,862)	(266,735)	0	(849,597)	1,131,188
8	1915	Office Furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0
10	1920	Computer Equipment - Hardware	5,516,356	1,462,574	0	6,978,930	(2,597,577)	(1,216,848)	0	(3,814,426)	3,164,504
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	607,136	228,106	0	835,242	(177,632)	(154,113)	0	(331,745)	503,497
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	10,079,205	2,082,165	(1,171)	12,160,199	(1,543,046)	(1,020,181)	0	(2,563,227)	9,596,971
8	1935	Stores Equipment	583,608	0	0	583,608	(144,937)	(47,211)	0	(192,148)	391,459
8	1940	Tools, Shop & Garage Equipment	4,467,458	421,820	0	4,889,278	(1,294,639)	(665,437)	0	(1,960,076)	2,929,202
8	1945	Measurement & Testing Equipment	266,321	99,017	0	365,338	(86,980)	(45,327)	0	(132,306)	233,032
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	1,293,734	494,550	0	1,788,283	(342,889)	(211,010)	0	(553,899)	1,234,384
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	257,686	52,104	0	309,791	(53,278)	(32,156)	0	(85,434)	224,356
47	1970	Load Management Controls Customer Premises	291,538	0	0	291,538	(104,969)	(52,406)	0	(157,375)	134,163
47	1975	Load Management Controls Utility Premises	39,548	0	0	39,548	(14,397)	(7,189)	0	(21,586)	17,962
47	1980	System Supervisor Equipment	7,545,735	341,136	0	7,886,870	(1,455,385)	(726,019)	0	(2,181,404)	5,705,466
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	0	0	0	0	0	0	0	0	0
47	2440	Deferred Revenue[5]	(43,240,801)	(21,418,578)	0	(64,659,379)	1,134,479	1,433,963	0	2,568,441	(62,090,938)
	1609	Capital Contributions Paid	2,106,099	354,447	0	2,460,546	(107,280)	(54,977)	0	(162,256)	2,298,290
		Sub-Total	**$626,263,438**	**$107,847,280**	**($3,940,774)**	**$730,169,944**	**($75,369,509)**	**($39,798,292)**	**$1,138,182**	**($114,029,619)**	**$616,140,325**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -				$ -	$ -
		Total PP&E	**$ 626,263,438**	**$ 107,847,280**	**-$ 3,940,774**	**$ 730,169,944**	**-$ 75,369,509**	**-$ 39,798,292**	**$ 1,138,182**	**-$ 114,029,619**	**$ 616,140,325**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 39,798,292**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 39,798,292

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: MIFRS
Year: 2014

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Adj to IFRS	Cost: Opening Balance IFRS	Cost: Forecast Additions	Cost: Actual Additions	Cost: Forecast Disposals	Cost: Actual Disposals	Cost: Forecast Closing Balance	Cost: Actual Closing Balance	Accumulated Depreciation: Opening Balance MIFRS	Accumulated Depreciation: Adj to IFRS	Accumulated Depreciation: Opening Balance IFRS	Accumulated Depreciation: Forecast Additions	Accumulated Depreciation: Actual Additions	Accumulated Depreciation: Forecast Disposals	Accumulated Depreciation: Actual Disposals	Accumulated Depreciation: Forecast Closing Balance	Accumulated Depreciation: Actual Closing Balance	Forecast Net Book Value	Actual Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	28,260,152	(21,520,260)	6,739,892	**35,904,265**	**33,247,992**	**(30,413)**	**(30,413)**	42,613,743	**39,957,471**	(22,518,154)	22,518,154	0	(6,484,309)	**(5,669,695)**	30,413	**30,413**	(6,453,896)	**(5,639,282)**	36,159,847	**34,318,189**
CEC	1612	Land Rights (Formally known as Account 1906)	1,924,292	(145,922)	1,778,370	**9,045**	**11,336**	**0**	**0**	1,787,415	**1,789,706**	(146,095)	146,095	0	(49,926)	**(48,951)**	0	**0**	(49,926)	**(48,951)**	1,737,489	**1,740,755**
N/A	1805	Land	24,932,864	0	24,932,864	**61,800**	**0**	**0**	**0**	24,994,664	**24,932,864**	0	0	0	0	**0**	0	**0**	0	**0**	24,994,664	**24,932,864**
47	1808	Buildings	26,587,472	(1,429,685)	25,157,788	**1,399,089**	**1,043,905**	**0**	**0**	26,556,877	**26,201,692**	(1,729,315)	1,729,315	0	(744,457)	**(771,699)**	0	**0**	(744,457)	**(771,699)**	25,812,419	**25,429,993**
13	1810	Leasehold Improvements	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
47	1815	Transformer Station Equipment >50 kV	78,340,731	(5,486,042)	72,854,689	**5,012,250**	**11,296,788**	**(2,870)**	**(2,870)**	77,864,068	**84,148,606**	(6,637,114)	6,637,114	0	(2,854,206)	**(2,812,209)**	2,870	**2,870**	(2,851,335)	**(2,809,338)**	75,012,733	**81,339,268**
47	1820	Distribution Station Equipment <50 kV	62,743,098	(8,676,698)	54,066,400	**8,308,506**	**9,889,514**	**(138,213)**	**(167,602)**	62,236,694	**63,788,312**	(10,272,620)	10,272,620	0	(3,703,635)	**(4,029,612)**	31,990	**34,547**	(3,671,646)	**(3,995,065)**	58,565,048	**59,793,247**
47	1825	Storage Battery Equipment	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
47	1830	Poles, Towers & Fixtures	80,588,905	(11,394,993)	69,193,912	**10,980,360**	**12,689,824**	**(172,091)**	**(189,960)**	80,002,181	**81,693,775**	(5,320,624)	5,320,624	0	(2,186,176)	**(2,037,593)**	1,142	**1,615**	(2,185,035)	**(2,035,978)**	77,817,147	**79,657,797**
47	1835	Overhead Conductors & Devices	67,900,095	(9,142,444)	58,757,651	**12,474,266**	**12,807,475**	**(44,536)**	**(50,285)**	71,187,381	**71,514,841**	(4,460,846)	4,460,846	0	(1,945,450)	**(1,862,821)**	3,678	**3,923**	(1,941,773)	**(1,858,898)**	69,245,609	**69,655,944**
47	1840	Underground Conduit	80,234,625	(21,297,534)	58,937,092	**15,031,081**	**15,793,480**	**0**	**0**	73,968,173	**74,730,572**	(6,544,295)	6,544,295	0	(2,747,147)	**(2,338,895)**	0	**0**	(2,747,147)	**(2,338,895)**	71,221,027	**72,391,677**
47	1845	Underground Conductors & Devices	92,473,992	(27,236,909)	65,237,083	**15,539,739**	**15,320,231**	**(956,489)**	**(1,163,022)**	79,820,332	**79,394,292**	(10,483,685)	10,483,685	0	(3,941,668)	**(3,402,953)**	419,504	**432,747**	(3,522,164)	**(2,970,205)**	76,298,168	**76,424,086**
47	1850	Line Transformers	65,154,980	(19,498,267)	45,656,713	**9,327,222**	**8,677,272**	**(124,321)**	**(211,115)**	54,859,614	**54,122,870**	(5,889,582)	5,889,582	(0)	(2,304,902)	**(1,808,549)**	1,704	**5,014**	(2,303,198)	**(1,803,535)**	52,556,416	**52,319,335**
47	1855	Services (Overhead & Underground)	52,080,726	(12,796,073)	39,284,653	**3,756,628**	**4,169,964**	**0**	**0**	43,041,281	**43,454,617**	(3,811,010)	3,811,010	0	(1,436,917)	**(1,228,496)**	0	**0**	(1,436,917)	**(1,228,496)**	41,604,364	**42,226,121**
47	1860	Meters	10,859,154	(10,014,300)	844,854	**710,311**	**638,376**	**(3,050)**	**(5,077)**	1,552,115	**1,478,152**	(9,180,811)	9,180,811	0	(103,332)	**(32,493)**	89	**329**	(103,244)	**(32,164)**	1,448,871	**1,445,988**
47	1860	Meters (Smart Meters)	45,623,797	(10,631,381)	34,992,415	**1,661,001**	**1,466,096**	**(151,106)**	**(3,335,953)**	36,502,311	**33,122,559**	(10,617,462)	10,617,462	0	(3,784,776)	**(3,762,053)**	6,280	**1,950,786**	(3,778,496)	**(1,811,268)**	32,723,815	**31,311,291**
N/A	1905	Land	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
47	1908	Buildings & Fixtures	36,554,484	(5,254,414)	31,300,071	**533,618**	**461,712**	**(1,531)**	**(1,531)**	31,832,157	**31,760,252**	(5,980,967)	5,980,967	0	(1,744,436)	**(1,806,061)**	1,531	**1,531**	(1,742,905)	**(1,804,530)**	30,089,252	**29,955,722**
13	1910	Leasehold Improvements	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
8	1915	Office Furniture & Equipment (10 years)	1,980,784	(839,464)	1,141,320	**117,204**	**66,370**	**(11,764)**	**(11,764)**	1,246,760	**1,195,926**	(849,597)	849,597	0	(248,753)	**(242,227)**	11,764	**11,764**	(236,989)	**(230,463)**	1,009,771	**965,464**
8	1915	Office Furniture & Equipment (5 years)	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
10	1920	Computer Equipment - Hardware	6,978,930	(3,826,054)	3,152,876	**1,063,718**	**873,755**	**(61,378)**	**(61,378)**	4,155,215	**3,965,253**	(3,814,426)	3,814,426	0	(1,266,141)	**(1,188,624)**	61,378	**61,378**	(1,204,763)	**(1,127,246)**	2,950,452	**2,838,007**
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	835,242	(330,536)	504,706	**539,472**	**626,319**	**0**	**0**	1,044,177	**1,131,025**	(331,745)	331,745	0	(148,732)	**(221,165)**	0	**0**	(148,732)	**(221,165)**	895,445	**909,860**
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
10	1930	Transportation Equipment	12,160,199	(3,189,240)	8,970,959	**2,429,332**	**2,197,399**	**(20,898)**	**(20,898)**	11,379,393	**11,147,461**	(2,563,227)	2,563,227	0	(1,453,870)	**(1,099,671)**	1,838	**1,838**	(1,452,032)	**(1,097,833)**	9,927,361	**10,049,628**
8	1935	Stores Equipment	583,608	(255,011)	328,597	**423,432**	**430,559**	**0**	**0**	752,029	**759,156**	(192,148)	192,148	0	(80,904)	**(64,345)**	0	**0**	(80,904)	**(64,345)**	671,125	**694,811**
8	1940	Tools, Shop & Garage Equipment	4,889,278	(1,939,659)	2,949,619	**329,285**	**316,398**	**(10,833)**	**(10,833)**	3,268,071	**3,255,184**	(1,960,076)	1,960,076	0	(691,829)	**(670,059)**	10,833	**10,833**	(680,996)	**(659,225)**	2,587,075	**2,595,959**
8	1945	Measurement & Testing Equipment	365,338	(128,854)	236,485	**536**	**536**	**(8,191)**	**(8,191)**	228,830	**228,830**	(132,306)	132,306	0	(38,354)	**(39,082)**	8,191	**8,191**	(30,163)	**(30,891)**	198,667	**197,939**
8	1950	Power Operated Equipment	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
8	1955	Communications Equipment	1,788,283	(543,261)	1,245,022	**251,596**	**327,806**	**0**	**0**	1,496,619	**1,572,828**	(553,899)	553,899	0	(151,452)	**(213,561)**	0	**0**	(151,452)	**(213,561)**	1,345,167	**1,359,267**
8	1955	Communication Equipment (Smart Meters)	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
8	1960	Miscellaneous Equipment	309,791	(82,499)	227,291	**1,962**	**5,092**	**0**	**0**	229,253	**232,383**	(85,434)	85,434	0	(33,856)	**(35,410)**	0	**0**	(33,856)	**(35,410)**	195,397	**196,973**
47	1970	Load Management Controls Customer Premises	291,538	(157,292)	134,245	**0**	**0**	**0**	**0**	134,245	**134,245**	(157,375)	157,375	0	(52,406)	**(52,426)**	0	**0**	(52,406)	**(52,426)**	81,839	**81,819**
47	1975	Load Management Controls Utility Premises	39,548	(21,573)	17,974	**0**	**0**	**0**	**0**	17,974	**17,974**	(21,586)	21,586	0	(7,189)	**(7,194)**	0	**0**	(7,189)	**(7,194)**	10,786	**10,781**
47	1980	System Supervisor Equipment	7,886,870	(2,165,962)	5,720,909	**541,583**	**488,755**	**(4,483)**	**(4,483)**	6,258,009	**6,205,181**	(2,181,404)	2,181,404	0	(728,783)	**(723,482)**	4,483	**4,483**	(724,300)	**(718,999)**	5,533,709	**5,486,181**
47	1985	Miscellaneous Fixed Assets	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
47	1990	Other Tangible Property	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
47	1995	Contributions & Grants	0	0	0	**0**	**0**	**0**	**0**	0	**0**	0	0	0	0	**0**	0	**0**	0	**0**	0	**0**
47	2440	Deferred Revenue5	(64,659,379)	64,659,379	0	**(20,143,565)**	**(23,624,645)**	**0**	**0**	(20,143,565)	**(23,624,645)**	2,568,441	(2,568,441)	0	2,537,165	**318,161**	0	**0**	2,537,165	**318,161**	(17,606,400)	**(23,306,484)**
	1609	Capital Contributions Paid	2,460,546	(182,190)	2,278,356	**7,708,451**	**636,501**	**0**	**0**	9,986,807	**2,914,857**	(162,256)	162,256	0	(120,565)	**(71,858)**	0	**0**	(120,565)	**(71,858)**	9,866,242	**2,842,999**
		Sub-Total	**$730,169,943**	**($113,527,137)**	**$616,642,806**	**$113,972,186**	**$109,858,808**	**($1,742,167)**	**($5,275,374)**	**$728,872,825**	**$721,226,240**	**($114,029,619)**	**$114,029,619**	**($0)**	**($36,517,006)**	**($35,923,023)**	**$597,688**	**$2,562,263**	**($35,919,318)**	**($33,360,760)**	**$692,953,507**	**$687,865,481**
		Less Socialized Renewable Energy Generation Investments (input as negative)								$ -	$ -								$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)								$ -	$ -								$ -	$ -	$ -	$ -
		Total PP&E	**$730,169,943**	**($113,527,137)**	**$616,642,806**	**$113,972,186**	**$109,858,808**	**($1,742,167)**	**($5,275,374)**	**$728,872,825**	**$721,226,240**	**($114,029,619)**	**$114,029,619**	**($0)**	**($36,517,006)**	**($35,923,023)**	**$597,688**	**$2,562,263**	**($35,919,318)**	**($33,360,760)**	**$692,953,507**	**$687,865,481**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]																				
		Forecast Total													**($36,517,006)**							
		Actual Total													**($35,923,023)**							

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Forecast Net Depreciation **($36,517,006)**
Actual Net Depreciation **($35,923,023)**

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2015

			Cost							Accumulated Depreciation								
CCA Class	**OEB**	**Description**	**Original Opening Balance**	**Opening Balance**	**Original Additions**	**Additions**	**Disposals**	**Original Closing Balance**	**Closing Balance**	**Original Opening Balance**	**Opening Balance**	**Original Additions**	**Additions**	**Disposals**	**Original Closing Balance**	**Closing Balance**	**Original Net Book Value**	**Closing Balance**
12	1611	Computer Software (Formally known as Account 1925)	42,613,743	39,957,471	8,494,616	8,494,616	0	51,108,359	48,452,087	(6,453,896)	(5,639,282)	(6,842,769)	(6,737,769)	0	(13,296,665)	(12,377,051)	37,811,694	36,075,035
CEC	1612	Land Rights (Formally known as Account 1906)	1,787,415	1,789,706	47,888	47,888	0	1,835,303	1,837,594	(49,926)	(48,951)	(49,427)	(49,427)	0	(99,353)	(98,378)	1,735,950	1,739,216
N/A	1805	Land	24,994,664	24,932,864	56,376	56,376	0	25,051,040	24,989,240	0	0	0	0	0	0	0	25,051,040	24,989,240
47	1808	Buildings	26,556,877	26,201,692	1,767,356	1,767,356	0	28,324,232	27,969,048	(744,457)	(771,699)	(808,230)	(808,230)	0	(1,552,687)	(1,579,928)	26,771,545	26,389,119
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	77,864,068	84,148,606	9,155,389	9,155,389	0	87,019,457	93,303,995	(2,851,335)	(2,809,338)	(3,144,274)	(3,118,588)	0	(5,995,609)	(5,927,926)	81,023,848	87,376,069
47	1820	Distribution Station Equipment <50 kV	62,236,694	63,788,312	14,881,533	14,881,533	(153,346)	76,964,881	78,516,499	(3,671,646)	(3,995,065)	(3,566,264)	(3,525,914)	91,547	(7,146,362)	(7,429,432)	69,818,519	71,087,068
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	80,002,181	81,693,775	11,425,160	11,425,160	(176,894)	91,250,447	92,942,041	(2,185,035)	(2,035,978)	(2,548,240)	(2,298,813)	85,385	(4,647,889)	(4,249,406)	86,602,557	88,692,635
47	1835	Overhead Conductors & Devices	71,187,381	71,514,841	12,523,986	12,523,986	(139,822)	83,571,546	83,899,005	(1,941,773)	(1,858,898)	(2,434,302)	(2,151,059)	118,010	(4,258,065)	(3,891,947)	79,313,481	80,007,059
47	1840	Underground Conduit	73,968,173	74,730,572	15,060,044	15,060,044	0	89,028,217	89,790,616	(2,747,147)	(2,338,895)	(3,733,364)	(2,719,930)	0	(6,480,511)	(5,058,825)	82,547,706	84,731,791
47	1845	Underground Conductors & Devices	79,820,332	79,394,292	16,750,871	16,750,871	(882,544)	95,688,659	95,262,619	(3,522,164)	(2,970,205)	(4,899,089)	(3,454,273)	510,296	(7,910,957)	(5,914,183)	87,777,702	89,348,436
47	1850	Line Transformers	54,859,614	54,122,870	12,473,909	12,473,909	(211,886)	67,121,637	66,384,893	(2,303,198)	(1,803,535)	(3,607,516)	(2,209,944)	117,650	(5,793,064)	(3,895,829)	61,328,573	62,489,064
47	1855	Services (Overhead & Underground)	43,041,281	43,454,617	4,806,826	4,806,826	0	47,848,107	48,261,443	(1,436,917)	(1,228,496)	(2,297,983)	(1,330,215)	0	(3,734,900)	(2,558,711)	44,113,207	45,702,732
47	1860	Meters	1,552,115	1,478,152	772,217	772,217	(1,706)	2,322,626	2,248,663	(103,244)	(32,164)	(371,358)	(371,231)	125	(474,477)	(403,270)	1,848,149	1,845,394
47	1860	Meters (Smart Meters)	36,502,311	33,122,559	2,172,740	2,172,740	(148,671)	38,526,380	35,146,628	(3,778,496)	(1,811,268)	(3,925,421)	(3,826,592)	52,031	(7,651,886)	(5,585,828)	30,874,494	29,560,800
N/A	1905	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	31,832,157	31,760,252	492,252	492,252	0	32,324,409	32,252,504	(1,742,905)	(1,804,530)	(1,820,639)	(1,820,639)	0	(3,563,544)	(3,625,169)	28,760,865	28,627,335
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (10 years)	1,246,760	1,195,926	202,281	202,281	0	1,449,041	1,398,207	(236,989)	(230,463)	(242,372)	(242,372)	0	(479,362)	(472,835)	969,680	925,372
8	1915	Office Furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1920	Computer Equipment - Hardware	4,155,215	3,965,253	1,077,440	1,077,440	0	5,232,655	5,042,693	(1,204,763)	(1,127,246)	(1,216,914)	(1,216,914)	0	(2,421,677)	(2,344,160)	2,810,979	2,698,533
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	1,044,177	1,131,025	20,232	20,232	0	1,064,409	1,151,257	(148,732)	(221,165)	(257,793)	(257,793)	0	(406,525)	(478,957)	657,885	672,300
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	11,379,393	11,147,461	1,464,507	1,464,507	(48,184)	12,795,716	12,563,784	(1,452,032)	(1,097,833)	(1,255,180)	(1,255,180)	38,009	(2,669,202)	(2,315,003)	10,126,514	10,248,780
8	1935	Stores Equipment	752,029	759,156	72,821	72,821	0	824,850	831,977	(80,904)	(64,345)	(62,130)	(62,130)	0	(143,033)	(126,475)	681,816	705,502
8	1940	Tools, Shop & Garage Equipment	3,268,071	3,255,184	513,134	513,134	0	3,781,205	3,768,318	(680,996)	(659,225)	(664,268)	(664,268)	0	(1,345,263)	(1,323,493)	2,435,942	2,444,825
8	1945	Measurement & Testing Equipment	228,830	228,830	89	89	0	228,919	228,919	(30,163)	(30,891)	(30,319)	(30,319)	0	(60,482)	(61,210)	168,437	167,709
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	1,496,619	1,572,828	234,645	234,645	0	1,731,264	1,807,473	(151,452)	(213,561)	(238,551)	(238,551)	0	(390,002)	(452,112)	1,341,261	1,355,361
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	229,253	232,383	0	0	0	229,253	232,383	(33,856)	(35,410)	(35,188)	247,782	0	(69,045)	212,372	160,209	444,756
47	1970	Load Management Controls Customer Premises	134,245	134,245	0	0	0	134,245	134,245	(52,406)	(52,426)	(52,426)	(52,426)	0	(104,831)	(104,852)	29,414	29,394
47	1975	Load Management Controls Utility Premises	17,974	17,974	0	0	0	17,974	17,974	(7,189)	(7,194)	(7,194)	(7,194)	0	(14,382)	(14,387)	3,592	3,587
47	1980	System Supervisor Equipment	6,258,009	6,205,181	513,106	513,106	0	6,771,115	6,718,287	(724,300)	(718,999)	(788,097)	(757,314)	0	(1,512,397)	(1,476,314)	5,258,719	5,241,973
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	2440	Deferred Revenue5	(20,143,565)	(23,624,645)	(25,432,188)	(21,874,290)	0	(45,575,753)	(45,498,935)	2,537,165	318,161	6,833,629	1,035,123	0	9,370,794	1,353,283	(36,204,959)	(44,145,652)
	1609	Capital Contributions Paid	9,986,807	2,914,857	17,352,847	17,352,847	0	47,607,357	20,267,704	(120,565)	(71,858)	(492,096)	(492,096)	0	(612,660)	(563,954)	26,726,993	19,703,750
		Sub-Total	**$728,872,825**	**$721,226,240**	**$106,900,077**	**$110,457,975**	**($1,763,053)**	**$854,277,553**	**$829,921,162**	**($35,919,318)**	**($33,360,760)**	**($38,557,773)**	**($38,416,273)**	**$1,013,053**	**($73,464,038)**	**($70,763,980)**	**$760,545,811**	**$759,157,182**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -	$ -						$ -		$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -	$ -						$ -		$ -	$ -
		Total PP&E	**$728,872,825**	**$721,226,240**	**$106,900,077**	**$110,457,975**	**($1,763,053)**	**$854,277,553**	**$829,921,162**	**($35,919,318)**	**($33,360,760)**	**($38,557,773)**	**($38,416,273)**	**$1,013,053**	**($73,464,038)**	**($70,763,980)**	**$760,545,811**	**$759,157,182**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]																
		Forecast Total									**($38,557,773)**							
		Total									**($38,416,273)**							

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Forecast Net Depreciation	**($38,557,773)**
Updated Net Depreciation	**($38,416,273)**

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2016

CCA Class	OEB	Description	Cost: Original Opening Balance	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Original Closing Balance	Cost: Closing Balance	Accumulated Depreciation: Original Opening Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Original Additions	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Original Closing Balance	Accumulated Depreciation: Closing Balance	Original Net Book Value	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	51,108,359	48,452,087	5,746,639	0	56,854,998	54,198,726	(13,296,665)	(12,377,051)	(7,476,010)	(7,476,010)	0	(20,772,676)	(19,853,062)	36,082,323	34,345,664
CEC	1612	Land Rights (Formally known as Account 1906)	1,835,303	1,837,594	60,962	0	1,896,265	1,898,556	(99,353)	(98,378)	(50,652)	(50,652)	0	(150,005)	(149,030)	1,746,260	1,749,526
N/A	1805	Land	25,051,040	24,989,240	83,466	0	25,134,506	25,072,706	0	0	0	0	0	0	0	25,134,506	25,072,706
47	1808	Buildings	28,324,232	27,969,048	1,836,061	0	30,160,293	29,805,109	(1,552,687)	(1,579,928)	(839,899)	(839,899)	0	(2,392,586)	(2,419,827)	27,767,707	27,385,282
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	87,019,457	93,303,995	502,034	0	87,521,491	93,806,029	(5,995,609)	(5,927,926)	(3,157,712)	(3,132,025)	0	(9,153,321)	(9,059,951)	78,368,170	84,746,078
47	1820	Distribution Station Equipment <50 kV	76,964,881	78,516,499	14,861,294	(153,346)	91,672,829	93,224,447	(7,146,362)	(7,429,432)	(3,363,678)	(3,323,328)	91,547	(10,418,494)	(10,661,213)	81,254,336	82,563,235
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	91,250,447	92,942,041	10,912,340	(176,894)	101,985,893	103,677,487	(4,647,889)	(4,249,406)	(2,801,604)	(2,552,177)	85,385	(7,364,108)	(6,716,198)	94,621,784	96,961,289
47	1835	Overhead Conductors & Devices	83,571,546	83,899,005	11,154,075	(139,822)	94,585,799	94,913,258	(4,258,065)	(3,891,947)	(2,719,076)	(2,435,833)	118,010	(6,859,131)	(6,209,770)	87,726,668	88,703,489
47	1840	Underground Conduit	89,028,217	89,790,616	17,658,496	0	106,686,713	107,449,112	(6,480,511)	(5,058,825)	(4,150,193)	(3,136,759)	0	(10,630,704)	(8,195,584)	96,056,009	99,253,527
47	1845	Underground Conductors & Devices	95,688,659	95,262,619	17,768,578	(882,544)	112,574,693	112,148,653	(7,910,957)	(5,914,183)	(5,331,396)	(3,886,580)	510,296	(12,732,057)	(9,290,466)	99,842,636	102,858,186
47	1850	Line Transformers	67,121,637	66,384,893	10,588,745	(211,886)	77,498,496	76,761,752	(5,793,064)	(3,895,829)	(3,992,561)	(2,594,989)	117,650	(9,667,974)	(6,373,168)	67,830,522	70,388,584
47	1855	Services (Overhead & Underground)	47,848,107	48,261,443	4,641,415	0	52,489,522	52,902,858	(3,734,900)	(2,558,711)	(2,408,976)	(1,441,209)	0	(6,143,877)	(3,999,920)	46,345,645	48,902,938
47	1860	Meters	2,322,626	2,248,663	839,698	(1,706)	3,160,618	3,086,655	(474,477)	(403,270)	(425,965)	(425,838)	125	(900,317)	(828,982)	2,260,301	2,257,673
47	1860	Meters (Smart Meters)	38,526,380	35,146,628	2,239,212	(148,671)	40,616,921	37,237,169	(7,651,886)	(5,585,828)	(4,082,919)	(3,950,060)	52,031	(11,682,774)	(9,483,857)	28,934,147	27,753,312
N/A	1905	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	32,324,409	32,252,504	1,249,694	0	33,574,103	33,502,198	(3,563,544)	(3,625,169)	(1,855,444)	(1,855,444)	0	(5,418,988)	(5,480,614)	28,155,115	28,021,584
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (10 years)	1,449,041	1,398,207	202,162	0	1,651,203	1,600,369	(479,362)	(472,835)	(250,327)	(250,327)	0	(729,689)	(723,162)	921,515	877,207
8	1915	Office Furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1920	Computer Equipment - Hardware	5,232,655	5,042,693	3,046,928	0	8,279,583	8,089,621	(2,421,677)	(2,344,160)	(1,367,712)	(1,367,712)	0	(3,789,389)	(3,711,872)	4,490,195	4,377,749
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	1,064,409	1,151,257	20,216	0	1,084,625	1,171,473	(406,525)	(478,957)	(226,907)	(226,907)	0	(633,432)	(705,865)	451,194	465,608
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	12,795,716	12,563,784	1,289,703	(48,184)	14,037,235	13,805,303	(2,669,202)	(2,315,003)	(1,375,967)	(1,375,967)	38,009	(4,007,160)	(3,652,961)	10,030,075	10,152,342
8	1935	Stores Equipment	824,850	831,977	165,771	0	990,621	997,748	(143,033)	(126,475)	(68,346)	(68,346)	0	(211,379)	(194,821)	779,241	802,927
8	1940	Tools, Shop & Garage Equipment	3,781,205	3,768,318	512,676	0	4,293,881	4,280,994	(1,345,263)	(1,323,493)	(590,896)	(590,896)	0	(1,936,159)	(1,914,389)	2,357,722	2,366,606
8	1945	Measurement & Testing Equipment	228,919	228,919	195	0	229,114	229,114	(60,482)	(61,210)	(27,266)	(27,266)	0	(87,748)	(88,476)	141,366	140,638
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	1,731,264	1,807,473	1,876,347	0	3,607,611	3,683,820	(390,002)	(452,112)	(297,916)	(297,916)	0	(687,918)	(750,027)	2,919,693	2,933,793
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	229,253	232,383	1,361,293	0	1,590,546	1,593,676	(69,045)	212,372	(57,812)	225,159	0	(126,857)	437,531	1,463,689	2,031,207
47	1970	Load Management Controls Customer Premises	134,245	134,245	0	0	134,245	134,245	(104,831)	(104,852)	(27,781)	(27,781)	0	(132,612)	(132,632)	1,633	1,613
47	1975	Load Management Controls Utility Premises	17,974	17,974	0	0	17,974	17,974	(14,382)	(14,387)	(3,587)	(3,587)	0	(17,969)	(17,974)	5	0
47	1980	System Supervisor Equipment	6,771,115	6,718,287	574,547	0	7,345,662	7,292,834	(1,512,397)	(1,476,314)	(780,383)	(749,601)	0	(2,292,780)	(2,225,915)	5,052,883	5,066,919
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	2440	Deferred Revenue[5]	(45,575,753)	(45,498,935)	(25,701,824)	0	(71,277,577)	(71,200,759)	9,370,794	1,353,283	7,565,740	1,767,233	0	16,936,534	3,120,516	(54,341,043)	(68,080,243)
	1609	Capital Contributions Paid	27,339,654	20,267,704	4,890,441	0	32,230,095	25,158,145	(612,660)	(563,954)	(660,869)	(660,869)	0	(1,273,529)	(1,224,823)	30,956,565	23,933,322
		Sub-Total	**$834,009,849**	**$829,921,162**	**$88,381,164**	**($1,763,053)**	**$920,627,960**	**$916,539,273**	**($73,464,038)**	**($70,763,980)**	**($40,826,114)**	**($40,755,585)**	**$1,013,053**	**($113,277,099)**	**($110,506,512)**	**$807,350,861**	**$806,032,761**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -	$ -						$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -	$ -						$ -	$ -	$ -	$ -
		Total PP&E	**$834,009,849**	**$829,921,162**	**$88,381,164**	**($1,763,053)**	**$920,627,960**	**$916,539,273**	**($73,464,038)**	**($70,763,980)**	**($40,826,114)**	**($40,755,585)**	**$1,013,053**	**($113,277,099)**	**($110,506,512)**	**$807,350,861**	**$806,032,761**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]															
		Forecast Total									**($40,826,114)**						
		Total									**($40,755,585)**						

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Forecast Net Depreciation **($40,826,114)**
Updated Net Depreciation **($40,755,585)**

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	EB-2015-0004
Exhibit:	B
Tab:	2
Schedule:	1
Page:	6 of 9
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2017

			Cost						Accumulated Depreciation								
CCA Class	**OEB**	**Description**	**Original Opening Balance**	**Opening Balance**	**Additions**	**Disposals**	**Original Closing Balance**	**Closing Balance**	**Original Opening Balance**	**Opening Balance**	**Original Additions**	**Additions**	**Disposals**	**Original Closing Balance**	**Closing Balance**	**Original Net Book Value**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	56,854,998	54,198,726	14,487,488	0	71,342,486	68,686,214	(20,772,676)	(19,853,062)	(9,090,500)	(9,090,500)	0	(29,863,176)	(28,943,562)	41,479,311	39,742,652
CEC	1612	Land Rights (Formally known as Account 1906)	1,896,265	1,898,556	54,317	0	1,950,582	1,952,873	(150,005)	(149,030)	(51,667)	(51,667)	0	(201,672)	(200,697)	1,748,910	1,752,176
N/A	1805	Land	25,134,506	25,072,706	74,745	0	25,209,251	25,147,451	0	0	0	0	0	0	0	25,209,251	25,147,451
47	1808	Buildings	30,160,293	29,805,109	2,066,613	0	32,226,906	31,871,722	(2,392,586)	(2,419,827)	(852,913)	(852,913)	0	(3,245,499)	(3,272,740)	28,981,407	28,598,982
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	87,521,491	93,806,029	3,270,317	0	90,791,808	97,076,346	(9,153,321)	(9,059,951)	(3,176,044)	(3,150,358)	0	(12,329,365)	(12,210,309)	78,462,443	84,866,037
47	1820	Distribution Station Equipment <50 kV	91,672,829	93,224,447	7,281,006	(153,346)	98,800,489	100,352,107	(10,418,494)	(10,661,213)	(3,426,827)	(3,386,477)	91,547	(13,753,774)	(13,956,143)	85,046,716	86,395,965
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	101,985,893	103,677,487	9,641,272	(176,894)	111,450,271	113,141,865	(7,364,108)	(6,716,198)	(3,023,381)	(2,773,954)	85,385	(10,302,104)	(9,404,767)	101,148,166	103,737,099
47	1835	Overhead Conductors & Devices	94,585,799	94,913,258	10,561,884	(139,822)	105,007,861	105,335,320	(6,859,131)	(6,209,770)	(2,964,330)	(2,681,087)	118,010	(9,705,451)	(8,772,847)	95,302,410	96,562,474
47	1840	Underground Conduit	106,686,713	107,449,112	15,913,333	0	122,600,046	123,362,445	(10,630,704)	(8,195,584)	(4,555,873)	(3,542,439)	0	(15,186,577)	(11,738,023)	107,413,469	111,624,421
47	1845	Underground Conductors & Devices	112,574,693	112,148,653	15,799,995	(882,544)	127,492,144	127,066,104	(12,732,057)	(9,290,466)	(5,738,226)	(4,293,410)	510,296	(17,959,987)	(13,073,580)	109,532,157	113,992,523
47	1850	Line Transformers	77,498,496	76,761,752	11,268,691	(211,886)	88,555,301	87,818,557	(9,667,974)	(6,373,168)	(4,339,744)	(2,942,172)	117,650	(13,890,068)	(9,197,690)	74,665,233	78,620,867
47	1855	Services (Overhead & Underground)	52,489,522	52,902,858	4,462,139	0	56,951,661	57,364,997	(6,143,877)	(3,999,920)	(2,504,052)	(1,536,284)	0	(8,647,929)	(5,536,204)	48,303,732	51,828,793
47	1860	Meters	3,160,618	3,086,655	795,550	(1,706)	3,954,462	3,880,499	(900,317)	(828,982)	(479,211)	(479,084)	125	(1,379,403)	(1,307,941)	2,575,059	2,572,559
47	1860	Meters (Smart Meters)	40,616,921	37,237,169	3,422,515	(148,671)	43,890,765	40,511,013	(11,682,774)	(9,483,857)	(4,261,213)	(4,111,562)	52,031	(15,891,956)	(13,543,388)	27,998,809	26,967,625
N/A	1905	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	33,574,103	33,502,198	434,312	0	34,008,415	33,936,510	(5,418,988)	(5,480,614)	(1,832,004)	(1,832,004)	0	(7,250,992)	(7,312,618)	26,757,423	26,623,892
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (10 years)	1,651,203	1,600,369	80,864	0	1,732,067	1,681,233	(729,689)	(723,162)	(226,757)	(226,757)	0	(956,446)	(949,919)	775,622	731,314
8	1915	Office Furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1920	Computer Equipment - Hardware	8,279,583	8,089,621	936,580	0	9,216,163	9,026,201	(3,789,389)	(3,711,872)	(1,531,304)	(1,531,304)	0	(5,320,693)	(5,243,176)	3,895,471	3,783,025
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	1,084,625	1,171,473	20,622	0	1,105,247	1,192,095	(633,432)	(705,865)	(182,815)	(182,815)	0	(816,247)	(888,680)	289,001	303,415
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	14,037,235	13,805,303	1,035,059	(48,184)	15,024,110	14,792,178	(4,007,160)	(3,652,961)	(1,446,015)	(1,446,015)	38,009	(5,415,166)	(5,060,967)	9,608,944	9,731,211
8	1935	Stores Equipment	990,621	997,748	173,858	0	1,164,479	1,171,606	(211,379)	(194,821)	(79,506)	(79,506)	0	(290,885)	(274,327)	873,593	897,279
8	1940	Tools, Shop & Garage Equipment	4,293,881	4,280,994	521,576	0	4,815,457	4,802,570	(1,936,159)	(1,914,389)	(512,161)	(512,161)	0	(2,448,320)	(2,426,550)	2,367,137	2,376,021
8	1945	Measurement & Testing Equipment	229,114	229,114	110	0	229,224	229,224	(87,748)	(88,476)	(24,704)	(24,704)	0	(112,452)	(113,180)	116,772	116,044
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	3,607,611	3,683,820	1,507,683	0	5,115,294	5,191,503	(687,918)	(750,027)	(336,374)	(336,374)	0	(1,024,292)	(1,086,401)	4,091,002	4,105,102
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	1,590,546	1,593,676	2,912,498	0	4,503,044	4,506,174	(126,857)	437,531	(193,857)	89,114	0	(320,714)	526,645	4,182,330	5,032,819
47	1970	Load Management Controls Customer Premises	134,245	134,245	0	0	134,245	134,245	(132,612)	(132,632)	(1,613)	(1,613)	0	(134,225)	(134,245)	20	(0)
47	1975	Load Management Controls Utility Premises	17,974	17,974	0	0	17,974	17,974	(17,969)	(17,974)	0	0	0	(17,969)	(17,974)	5	0
47	1980	System Supervisor Equipment	7,345,662	7,292,834	462,587	0	7,808,249	7,755,421	(2,292,780)	(2,225,915)	(753,194)	(722,412)	0	(3,045,974)	(2,948,326)	4,762,276	4,807,094
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	2440	Deferred Revenue5	(71,277,577)	(71,200,759)	(25,296,257)	0	(96,573,834)	(96,497,016)	16,936,534	3,120,516	8,229,610	2,431,103	0	25,166,144	5,551,619	(71,407,690)	(90,945,397)
	1609	Capital Contributions Paid	32,230,095	25,158,145	5,000,000	0	37,230,095	30,158,145	(1,273,529)	(1,224,823)	(790,403)	(790,403)	0	(2,063,932)	(2,015,226)	35,166,162	28,142,919
		Sub-Total	**$920,627,960**	**$916,539,273**	**$86,889,357**	**($1,763,053)**	**$1,005,754,264**	**$1,001,665,577**	**($113,277,099)**	**($110,506,512)**	**($44,145,078)**	**($44,057,757)**	**$1,013,053**	**($156,409,124)**	**($153,551,216)**	**$849,345,140**	**$848,114,361**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -	$ -						$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -	$ -						$ -	$ -	$ -	$ -
		Total PP&E	**$920,627,960**	**$916,539,273**	**$86,889,357**	**($1,763,053)**	**$1,005,754,264**	**$1,001,665,577**	**($113,277,099)**	**($110,506,512)**	**($44,145,078)**	**($44,057,757)**	**$1,013,053**	**($156,409,124)**	**($153,551,216)**	**$849,345,140**	**$848,114,361**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]															
		Forecast Total							**($44,145,078)**								
		Total							**($44,057,757)**								

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Forecast Net Depreciation	**($44,145,078)**
Updated Net Depreciation	**($44,057,757)**

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	EB-2015-0004
Exhibit:	B
Tab:	2
Schedule:	1
Page:	7 of 9
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year **2018**

			Cost						Accumulated Depreciation								
CCA Class	**OEB**	**Description**	**Original Opening Balance**	**Opening Balance**	**Additions**	**Disposals**	**Original Closing Balance**	**Closing Balance**	**Original Opening Balance**	**Opening Balance**	**Original Additions**	**Additions**	**Disposals**	**Original Closing Balance**	**Closing Balance**	**Original Net Book Value**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	71,342,486	68,686,214	4,427,066	0	75,769,552	73,113,280	(29,863,176)	(28,943,562)	(9,832,030)	(9,832,030)	0	(39,695,206)	(38,775,592)	36,074,347	34,337,688
CEC	1612	Land Rights (Formally known as Account 1906)	1,950,582	1,952,873	62,268	0	2,012,850	2,015,141	(201,672)	(200,697)	(52,833)	(52,833)	0	(254,505)	(253,530)	1,758,345	1,761,611
N/A	1805	Land	25,209,251	25,147,451	86,076	0	25,295,327	25,233,527	0	0	0	0	0	0	0	25,295,327	25,233,527
47	1808	Buildings	32,226,906	31,871,722	2,806,407	0	35,033,313	34,678,129	(3,245,499)	(3,272,740)	(887,113)	(887,113)	0	(4,132,612)	(4,159,853)	30,900,701	30,518,276
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	90,791,808	97,076,346	2,080,855	0	92,872,663	99,157,201	(12,329,365)	(12,210,309)	(3,249,345)	(3,223,659)	0	(15,578,710)	(15,433,968)	77,293,953	83,723,233
47	1820	Distribution Station Equipment <50 kV	98,800,489	100,352,107	21,080,999	(153,346)	119,728,142	121,279,760	(13,753,774)	(13,956,143)	(3,804,192)	(3,763,842)	91,547	(17,466,419)	(17,628,438)	102,261,724	103,651,323
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	111,450,271	113,141,865	10,665,681	(176,894)	121,939,058	123,630,652	(10,302,104)	(9,404,767)	(3,249,573)	(3,000,146)	85,385	(13,466,292)	(12,319,528)	108,472,765	111,311,125
47	1835	Overhead Conductors & Devices	105,007,861	105,335,320	11,850,925	(139,822)	116,718,964	117,046,423	(9,705,451)	(8,772,847)	(3,223,910)	(2,940,667)	118,010	(12,811,351)	(11,595,504)	103,907,613	105,450,920
47	1840	Underground Conduit	122,600,046	123,362,445	16,732,365	0	139,332,411	140,094,810	(15,186,577)	(11,738,023)	(4,970,108)	(3,956,674)	0	(20,156,685)	(15,694,697)	119,175,726	124,400,112
47	1845	Underground Conductors & Devices	127,492,144	127,066,104	16,687,693	(882,544)	143,297,293	142,871,253	(17,959,987)	(13,073,580)	(6,166,168)	(4,721,352)	510,296	(23,615,859)	(17,284,636)	119,681,434	125,586,616
47	1850	Line Transformers	88,555,301	87,818,557	11,745,128	(211,886)	100,088,543	99,351,799	(13,890,068)	(9,197,690)	(4,715,034)	(3,317,462)	117,650	(18,487,452)	(12,397,502)	81,601,091	86,954,297
47	1855	Services (Overhead & Underground)	56,951,661	57,364,997	4,653,541	0	61,605,202	62,018,538	(8,647,929)	(5,536,204)	(2,605,361)	(1,637,593)	0	(11,253,290)	(7,173,798)	50,351,912	54,844,740
47	1860	Meters	3,954,462	3,880,499	789,986	(1,706)	4,742,742	4,668,779	(1,379,403)	(1,307,941)	(525,269)	(525,142)	125	(1,904,547)	(1,832,957)	2,838,195	2,835,822
47	1860	Meters (Smart Meters)	43,890,765	40,511,013	3,459,747	(148,671)	47,201,841	43,822,089	(15,891,956)	(13,543,388)	(4,490,622)	(4,324,307)	52,031	(20,330,547)	(17,815,664)	26,871,294	26,006,425
N/A	1905	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	34,008,415	33,936,510	123,306	0	34,131,721	34,059,816	(7,250,992)	(7,312,618)	(1,762,299)	(1,762,299)	0	(9,013,291)	(9,074,917)	25,118,430	24,984,899
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (10 years)	1,732,067	1,681,233	40,432	0	1,772,499	1,721,665	(956,446)	(949,919)	(171,883)	(171,883)	0	(1,128,329)	(1,121,802)	644,171	599,863
8	1915	Office Furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1920	Computer Equipment - Hardware	9,216,163	9,026,201	995,222	0	10,211,385	10,021,423	(5,320,693)	(5,243,176)	(1,454,736)	(1,454,736)	0	(6,775,429)	(6,697,912)	3,435,957	3,323,511
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	1,105,247	1,192,095	21,039	0	1,126,286	1,213,134	(816,247)	(888,680)	(143,197)	(143,197)	0	(959,444)	(1,031,877)	166,843	181,257
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	15,024,110	14,792,178	1,451,508	(48,184)	16,427,434	16,195,502	(5,415,166)	(5,060,967)	(1,483,849)	(1,483,849)	38,009	(6,861,006)	(6,506,807)	9,566,428	9,688,695
8	1935	Stores Equipment	1,164,479	1,171,606	0	0	1,164,479	1,171,606	(290,885)	(274,327)	(85,302)	(85,302)	0	(376,187)	(359,629)	788,291	811,977
8	1940	Tools, Shop & Garage Equipment	4,815,457	4,802,570	530,821	0	5,346,278	5,333,391	(2,448,320)	(2,426,550)	(490,397)	(490,397)	0	(2,938,717)	(2,916,947)	2,407,561	2,416,445
8	1945	Measurement & Testing Equipment	229,224	229,224	210	0	229,434	229,434	(112,452)	(113,180)	(24,053)	(24,053)	0	(136,505)	(137,233)	92,929	92,201
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	5,115,294	5,191,503	1,510,081	0	6,625,375	6,701,584	(1,024,292)	(1,086,401)	(389,357)	(389,357)	0	(1,413,649)	(1,475,758)	5,211,726	5,225,826
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	4,503,044	4,506,174	1,610,265	0	6,113,309	6,116,439	(320,714)	526,645	(470,314)	(187,343)	0	(791,028)	339,301	5,322,281	6,455,741
47	1970	Load Management Controls Customer Premises	134,245	134,245	0	0	134,245	134,245	(134,225)	(134,245)	0	0	0	(134,225)	(134,245)	20	(0)
47	1975	Load Management Controls Utility Premises	17,974	17,974	0	0	17,974	17,974	(17,969)	(17,974)	0	0	0	(17,969)	(17,974)	5	0
47	1980	System Supervisor Equipment	7,808,249	7,755,421	612,188	0	8,420,437	8,367,609	(3,045,974)	(2,948,326)	(756,591)	(725,809)	0	(3,802,565)	(3,674,135)	4,617,873	4,693,474
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	2440	Deferred Revenue5	(96,573,834)	(96,497,016)	(25,075,051)	0	(121,648,885)	(121,572,067)	25,166,144	5,551,619	8,805,600	3,007,093	0	33,971,744	8,558,713	(87,677,141)	(113,013,354)
	1609	Capital Contributions Paid	37,230,095	30,158,145	5,277,020	0	42,507,115	35,435,165	(2,063,932)	(2,015,226)	(849,473)	(849,473)	0	(2,913,405)	(2,864,699)	39,593,709	32,570,466
		Sub-Total	**$1,005,754,264**	**$1,001,665,577**	**$94,225,778**	**($1,763,053)**	**$1,098,216,989**	**$1,094,128,302**	**($156,409,124)**	**($153,551,216)**	**($47,047,409)**	**($46,943,424)**	**$1,013,053**	**($202,443,480)**	**($199,481,586)**	**$895,773,509**	**$894,646,716**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -	$ -						$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -	$ -						$ -	$ -	$ -	$ -
		Total PP&E	**$1,005,754,264**	**$1,001,665,577**	**$94,225,778**	**($1,763,053)**	**$1,098,216,989**	**$1,094,128,302**	**($156,409,124)**	**($153,551,216)**	**($47,047,409)**	**($46,943,424)**	**$1,013,053**	**($202,443,480)**	**($199,481,586)**	**$895,773,509**	**$894,646,716**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]															
		Forecast Total							**($47,047,409)**								
		Total							**($46,943,424)**								

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Forecast Net Depreciation **($47,047,409)**
Updated Net Depreciation **($46,943,424)**

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

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4 The additions column (E) must not include construction work in progress (CWIP).

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File Number:	EB-2015-0004
Exhibit:	B
Tab:	2
Schedule:	1
Page:	8 of 9
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2019

CCA Class	OEB	Description	Cost: Original Opening Balance	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Original Closing Balance	Cost: Closing Balance	Accumulated Depreciation: Original Opening Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Original Additions	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Original Closing Balance	Accumulated Depreciation: Closing Balance	Original Net Book Value	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	75,769,552	73,113,280	4,325,277	0	80,094,829	77,438,557	(39,695,206)	(38,775,592)	(9,854,403)	(9,854,403)	0	(49,549,609)	(48,629,995)	30,545,221	28,808,562
CEC	1612	Land Rights (Formally known as Account 1906)	2,012,850	2,015,141	56,723	0	2,069,573	2,071,864	(254,505)	(253,530)	(54,023)	(54,023)	0	(308,528)	(307,553)	1,761,045	1,764,311
N/A	1805	Land	25,295,327	25,233,527	78,066	0	25,373,393	25,311,593	0	0	0	0	0	0	0	25,373,393	25,311,593
47	1808	Buildings	35,033,313	34,678,129	612,390	0	35,645,703	35,290,519	(4,132,612)	(4,159,853)	(921,932)	(921,932)	0	(5,054,544)	(5,081,785)	30,591,159	30,208,734
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	92,872,663	99,157,201	296,350	0	93,169,013	99,453,551	(15,578,710)	(15,433,968)	(3,277,184)	(3,251,498)	0	(18,855,894)	(18,685,465)	74,313,119	80,768,086
47	1820	Distribution Station Equipment <50 kV	119,728,142	121,279,760	6,540,900	(153,346)	126,115,696	127,667,314	(17,466,419)	(17,628,438)	(4,112,271)	(4,071,921)	91,547	(21,487,143)	(21,608,812)	104,628,554	106,058,503
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	121,939,058	123,630,652	9,999,245	(176,894)	131,761,409	133,453,003	(13,466,292)	(12,319,528)	(3,478,871)	(3,229,444)	85,385	(16,859,778)	(15,463,587)	114,901,630	117,989,417
47	1835	Overhead Conductors & Devices	116,718,964	117,046,423	10,901,888	(139,822)	127,481,030	127,808,489	(12,811,351)	(11,595,504)	(3,486,791)	(3,203,548)	118,010	(16,180,132)	(14,681,041)	111,300,898	113,127,448
47	1840	Underground Conduit	139,332,411	140,094,810	15,564,684	0	154,897,095	155,659,494	(20,156,685)	(15,694,697)	(5,338,917)	(4,325,483)	0	(25,495,602)	(20,020,180)	129,401,493	135,639,313
47	1845	Underground Conductors & Devices	143,297,293	142,871,253	14,669,994	(882,544)	157,084,743	156,658,703	(23,615,859)	(17,284,636)	(6,567,209)	(5,122,393)	510,296	(29,672,772)	(21,896,733)	127,411,971	134,761,970
47	1850	Line Transformers	100,088,543	99,351,799	11,457,891	(211,886)	111,334,548	110,597,804	(18,487,452)	(12,397,502)	(5,093,370)	(3,695,798)	117,650	(23,463,172)	(15,975,650)	87,871,376	94,622,154
47	1855	Services (Overhead & Underground)	61,605,202	62,018,538	4,621,673	0	66,226,875	66,640,211	(11,253,290)	(7,173,798)	(2,704,372)	(1,736,604)	0	(13,957,662)	(8,910,402)	52,269,213	57,729,809
47	1860	Meters	4,742,742	4,668,779	805,470	(1,706)	5,546,506	5,472,543	(1,904,547)	(1,832,957)	(548,655)	(548,528)	125	(2,453,077)	(2,381,360)	3,093,429	3,091,184
47	1860	Meters (Smart Meters)	47,201,841	43,822,089	3,535,732	(148,671)	50,588,902	47,209,150	(20,330,547)	(17,815,664)	(4,723,805)	(4,536,499)	52,031	(25,002,321)	(22,300,132)	25,586,581	24,909,018
N/A	1905	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	34,131,721	34,059,816	248,527	0	34,380,248	34,308,343	(9,013,291)	(9,074,917)	(1,714,509)	(1,714,509)	0	(10,727,800)	(10,789,426)	23,652,448	23,518,917
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (10 years)	1,772,499	1,721,665	80,864	0	1,853,363	1,802,529	(1,128,329)	(1,121,802)	(137,970)	(137,970)	0	(1,266,299)	(1,259,772)	587,065	542,757
8	1915	Office Furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1920	Computer Equipment - Hardware	10,211,385	10,021,423	879,384	0	11,090,769	10,900,807	(6,775,429)	(6,697,912)	(1,405,067)	(1,405,067)	0	(8,180,496)	(8,102,979)	2,910,274	2,797,828
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	1,126,286	1,213,134	21,464	0	1,147,750	1,234,598	(959,444)	(1,031,877)	(72,106)	(72,106)	0	(1,031,550)	(1,103,983)	116,201	130,615
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	16,427,434	16,195,502	1,479,811	(48,184)	17,859,061	17,627,129	(6,861,006)	(6,506,807)	(1,499,427)	(1,499,427)	38,009	(8,322,424)	(7,968,225)	9,536,637	9,658,904
8	1935	Stores Equipment	1,164,479	1,171,606	0	0	1,164,479	1,171,606	(376,187)	(359,629)	(85,302)	(85,302)	0	(461,489)	(444,931)	702,989	726,675
8	1940	Tools, Shop & Garage Equipment	5,346,278	5,333,391	539,893	0	5,886,171	5,873,284	(2,938,717)	(2,916,947)	(485,401)	(485,401)	0	(3,424,118)	(3,402,348)	2,462,053	2,470,937
8	1945	Measurement & Testing Equipment	229,434	229,434	33	0	229,467	229,467	(136,505)	(137,233)	(23,408)	(23,408)	0	(159,913)	(160,641)	69,554	68,826
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	6,625,375	6,701,584	1,368,157	0	7,993,532	8,069,741	(1,413,649)	(1,475,758)	(434,225)	(434,225)	0	(1,847,874)	(1,909,983)	6,145,658	6,159,758
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	6,113,309	6,116,439	722,548	0	6,835,857	6,838,987	(791,028)	339,301	(618,190)	(335,219)	0	(1,409,218)	4,082	5,426,639	6,843,069
47	1970	Load Management Controls Customer Premises	134,245	134,245	0	0	134,245	134,245	(134,225)	(134,245)	0	0	0	(134,225)	(134,245)	20	(0)
47	1975	Load Management Controls Utility Premises	17,974	17,974	0	0	17,974	17,974	(17,969)	(17,974)	0	0	0	(17,969)	(17,974)	5	0
47	1980	System Supervisor Equipment	8,420,437	8,367,609	384,007	0	8,804,444	8,751,616	(3,802,565)	(3,674,135)	(738,391)	(707,609)	0	(4,540,956)	(4,381,744)	4,263,489	4,369,872
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	2440	Deferred Revenue[5]	(121,648,885)	(121,572,067)	(25,576,549)	0	(147,225,434)	(147,148,616)	33,971,744	8,558,713	9,390,330	3,591,823	0	43,362,074	12,150,536	(103,863,360)	(134,998,080)
	1609	Capital Contributions Paid	42,507,115	35,435,165	5,000,000	0	47,507,115	40,435,165	(2,913,405)	(2,864,699)	(963,225)	(963,225)	0	(3,876,630)	(3,827,924)	43,630,484	36,607,241
		Sub-Total	**$1,098,216,989**	**$1,094,128,302**	**$68,614,422**	**($1,763,053)**	**$1,165,068,358**	**$1,160,979,671**	**($202,443,480)**	**($199,481,586)**	**($48,948,694)**	**($48,823,718)**	**$1,013,053**	**($250,379,121)**	**($247,292,251)**	**$914,689,237**	**$913,687,420**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -	$ -						$ -	$ -	$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -	$ -						$ -	$ -	$ -	$ -
		Total PP&E	**$1,098,216,989**	**$1,094,128,302**	**$68,614,422**	**($1,763,053)**	**$1,165,068,358**	**$1,160,979,671**	**($202,443,480)**	**($199,481,586)**	**($48,948,694)**	**($48,823,718)**	**$1,013,053**	**($250,379,121)**	**($247,292,251)**	**$914,689,237**	**$913,687,420**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]															
		Forecast Total							**($48,948,694)**								
		Total							**($48,823,718)**								

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Forecast Net Depreciation **($48,948,694)**
Updated Net Depreciation **($48,823,718)**

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

File Number:	EB-2015-0004
Exhibit:	B
Tab:	2
Schedule:	1
Page:	9 of 9
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2020

			Cost						Accumulated Depreciation								
CCA Class	**OEB**	**Description**	**Original Opening Balance**	**Opening Balance**	**Additions**	**Disposals**	**Original Closing Balance**	**Closing Balance**	**Original Opening Balance**	**Opening Balance**	**Original Additions**	**Additions**	**Disposals**	**Original Closing Balance**	**Closing Balance**	**Original Net Book Value**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	80,094,829	77,438,557	11,398,852	0	91,493,681	88,837,409	(49,549,609)	(48,629,995)	(9,608,727)	(9,608,727)	0	(59,158,336)	(58,238,722)	32,335,346	30,598,687
CEC	1612	Land Rights (Formally known as Account 1906)	2,069,573	2,071,864	59,142	0	2,128,715	2,131,006	(308,528)	(307,553)	(55,315)	(55,315)	0	(363,843)	(362,868)	1,764,872	1,768,138
N/A	1805	Land	25,373,393	25,311,593	81,467	0	25,454,860	25,393,060	0	0	0	0	0	0	0	25,454,860	25,393,060
47	1808	Buildings	35,645,703	35,290,519	7,064,436	0	42,710,139	42,354,955	(5,054,544)	(5,081,785)	(962,080)	(962,080)	0	(6,016,624)	(6,043,865)	36,693,515	36,311,090
13	1810	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1815	Transformer Station Equipment >50 kV	93,169,013	99,453,551	19,410,941	0	112,579,954	118,864,492	(18,855,894)	(18,685,465)	(3,260,988)	(3,235,302)	0	(22,116,882)	(21,920,767)	90,463,072	96,943,725
47	1820	Distribution Station Equipment <50 kV	126,115,696	127,667,314	14,870,523	(153,346)	140,832,873	142,384,491	(21,487,143)	(21,608,812)	(4,283,202)	(4,242,852)	91,547	(25,678,798)	(25,760,116)	115,154,076	116,624,375
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers & Fixtures	131,761,409	133,453,003	10,469,545	(176,894)	142,054,060	143,745,654	(16,859,778)	(15,463,587)	(3,712,067)	(3,462,640)	85,385	(20,486,460)	(18,840,841)	121,567,599	124,904,813
47	1835	Overhead Conductors & Devices	127,481,030	127,808,489	11,419,118	(139,822)	138,760,326	139,087,785	(16,180,132)	(14,681,041)	(3,749,711)	(3,466,468)	118,010	(19,811,833)	(18,029,499)	118,948,493	121,058,286
47	1840	Underground Conduit	154,897,095	155,659,494	16,160,263	0	171,057,358	171,819,757	(25,495,602)	(20,020,180)	(5,705,059)	(4,691,625)	0	(31,200,661)	(24,711,805)	139,856,697	147,107,951
47	1845	Underground Conductors & Devices	157,084,743	156,658,703	15,589,187	(882,544)	171,791,386	171,365,346	(29,672,772)	(21,896,733)	(6,951,688)	(5,506,872)	510,296	(36,114,164)	(26,893,309)	135,677,222	144,472,037
47	1850	Line Transformers	111,334,548	110,597,804	11,852,434	(211,886)	122,975,096	122,238,352	(23,463,172)	(15,975,650)	(5,481,196)	(4,083,624)	117,650	(28,826,718)	(19,941,625)	94,148,378	102,296,728
47	1855	Services (Overhead & Underground)	66,226,875	66,640,211	4,732,585	0	70,959,460	71,372,796	(13,957,662)	(8,910,402)	(2,810,332)	(1,842,564)	0	(16,767,994)	(10,752,966)	54,191,466	60,619,830
47	1860	Meters	5,546,506	5,472,543	821,639	(1,706)	6,366,439	6,292,476	(2,453,077)	(2,381,360)	(577,498)	(577,371)	125	(3,030,450)	(2,958,605)	3,335,989	3,333,871
47	1860	Meters (Smart Meters)	50,588,902	47,209,150	3,613,495	(148,671)	54,053,726	50,673,974	(25,002,321)	(22,300,132)	(4,972,542)	(4,776,181)	52,031	(29,922,832)	(27,024,282)	24,130,894	23,649,692
N/A	1905	Land	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1908	Buildings & Fixtures	34,380,248	34,308,343	132	0	34,380,380	34,308,475	(10,727,800)	(10,789,426)	(1,721,400)	(1,721,400)	0	(12,449,200)	(12,510,826)	21,931,180	21,797,649
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture & Equipment (10 years)	1,853,363	1,802,529	121,296	0	1,974,659	1,923,825	(1,266,299)	(1,259,772)	(133,586)	(133,586)	0	(1,399,885)	(1,393,358)	574,775	530,467
8	1915	Office Furniture & Equipment (5 years)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1920	Computer Equipment - Hardware	11,090,769	10,900,807	897,131	0	11,987,900	11,797,938	(8,180,496)	(8,102,979)	(1,356,374)	(1,356,374)	0	(9,536,870)	(9,459,353)	2,451,031	2,338,585
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	1,147,750	1,234,598	21,897	0	1,169,647	1,256,495	(1,031,550)	(1,103,983)	(20,883)	(20,883)	0	(1,052,433)	(1,124,866)	117,215	131,629
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1930	Transportation Equipment	17,859,061	17,627,129	1,572,486	(48,184)	19,383,363	19,151,431	(8,322,424)	(7,968,225)	(1,518,087)	(1,518,087)	38,009	(9,802,502)	(9,448,303)	9,580,861	9,703,128
8	1935	Stores Equipment	1,164,479	1,171,606	303,240	0	1,467,719	1,474,846	(461,489)	(444,931)	(95,569)	(95,569)	0	(557,058)	(540,500)	910,660	934,346
8	1940	Tools, Shop & Garage Equipment	5,886,171	5,873,284	549,412	0	6,435,583	6,422,696	(3,424,118)	(3,402,348)	(486,606)	(486,606)	0	(3,910,724)	(3,888,954)	2,524,859	2,533,743
8	1945	Measurement & Testing Equipment	229,467	229,467	0	0	229,467	229,467	(159,913)	(160,641)	(23,472)	(23,472)	0	(183,385)	(184,113)	46,082	45,354
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1955	Communications Equipment	7,993,532	8,069,741	3,179,757	0	11,173,289	11,249,498	(1,847,874)	(1,909,983)	(449,640)	(449,640)	0	(2,297,514)	(2,359,623)	8,875,775	8,889,875
8	1955	Communication Equipment (Smart Meters)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	6,835,857	6,838,987	0	0	6,835,857	6,838,987	(1,409,218)	4,082	(677,865)	(394,894)	0	(2,087,083)	(390,812)	4,748,774	6,448,175
47	1970	Load Management Controls Customer Premises	134,245	134,245	0	0	134,245	134,245	(134,225)	(134,245)	0	0	0	(134,225)	(134,245)	20	(0)
47	1975	Load Management Controls Utility Premises	17,974	17,974	0	0	17,974	17,974	(17,969)	(17,974)	0	0	0	(17,969)	(17,974)	5	0
47	1980	System Supervisor Equipment	8,804,444	8,751,616	530,571	0	9,335,015	9,282,187	(4,540,956)	(4,381,744)	(685,716)	(654,934)	0	(5,226,672)	(5,036,678)	4,108,344	4,245,509
47	1985	Miscellaneous Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1990	Other Tangible Property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	1995	Contributions & Grants	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47	2440	Deferred Revenue[5]	(147,225,434)	(147,148,616)	(26,088,080)	0	(173,313,514)	(173,236,696)	43,362,074	12,150,536	10,079,699	4,281,192	0	53,441,773	16,431,728	(119,871,741)	(156,804,968)
	1609	Capital Contributions Paid	47,507,115	40,435,165	5,030,454	0	52,537,569	45,465,619	(3,876,630)	(3,827,924)	(1,074,900)	(1,074,900)	0	(4,951,530)	(4,902,824)	47,586,039	40,562,795
		Sub-Total	**$1,165,068,358**	**$1,160,979,671**	**$113,661,923**	**($1,763,053)**	**$1,276,967,228**	**$1,272,878,541**	**($250,379,121)**	**($247,292,251)**	**($50,294,804)**	**($50,160,773)**	**$1,013,053**	**($299,660,872)**	**($296,439,971)**	**$977,306,356**	**$976,438,570**
		Less Socialized Renewable Energy Generation Investments (input as negative)					$ -							$ -		$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)					$ -							$ -		$ -	$ -
		Total PP&E	**$1,165,068,358**	**$1,160,979,671**	**$113,661,923**	**($1,763,053)**	**$1,276,967,228**	**$1,272,878,541**	**($250,379,121)**	**($247,292,251)**	**($50,294,804)**	**($50,160,773)**	**$1,013,053**	**($299,660,872)**	**($296,439,971)**	**$977,306,356**	**$976,438,570**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]															
		Forecast Total							**($50,294,804)**								
		Total							**($50,160,773)**								

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Forecast Net Depreciation **($50,294,804)**
Updated Net Depreciation **($50,160,773)**

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3 below).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

WORKING CAPITAL REQUIREMENT

1.0 INTRODUCTION

This Exhibit provides a schedule of the Working Capital Requirement for the bridge year (2015) and the test years (2016 - 2020). For comparison purposes, the approved and actual Working Capital Requirement for the base year (2012) is also shown.

Table 1 – Allowance for Working Capital[1]

	2012 Approved $000	2012 Actual $000	2013 Actual $000	2014 Forecast $000	2014 Actual $000	2015 Budget $000
Power Supply Expenses	685,303	709,935	768,079	763,312	799,272	851,135
OM&A Expenses	73,090	73,076	75,757	80,767	80,909	83,656
Total Expenses for Working Capital	758,393	783,011	843,836	844,079	880,181	934,791
Working Capital %	14.2	14.2	14.2	14.2	14.2	14.2
	107,692	111,188	119,825	119,859	124,986	132,740

	2016 Test $000	2017 Test $000	2018 Test $000	2019 Test $000	2020 Test $000
Power Supply Expenses	894,285	911,714	947,559	928,734	945,199
OM&A Expenses	87,106	89,932	92,850	95,863	98,974
Total Expenses for Working Capital	981,391	1,001,647	1,040,409	1,024,597	1,044,173
Working Capital %	14.2	14.2	14.2	14.2	14.2
	139,358	142,234	147,738	145,493	148,273

As part of Hydro Ottawa Limited's ("Hydro Ottawa") 2012 rate application, the Ontario Energy Board ("Board") approved a Working Capital Allowance percentage of 14.2. Hydro Ottawa submitted that it would implement monthly billing for all its customers in

[1] Totals may not match due to rounding

2013. As part of the decision and order the Board directed Hydro Ottawa to prepare a new lead-lag study for its next cost of service application.

In the first quarter of 2014 Hydro Ottawa implemented a new billing system. As part of this implementation Hydro Ottawa implemented monthly billing. Hydro Ottawa believes 12 months of stable monthly billing data is required to perform a new lead lag study. Hydro Ottawa is proposing to use data from July 2014 to June 2015 to complete its updated lead lag study. The new lead lag study will be submitted in September 2015 to be incorporated into final rates. Until the lead lag study is complete, Hydro Ottawa is using its 2012 Board approved rate of 14.2.

The Power Supply Expenses for 2016 to 2020 are calculated in the following manner:

The forecasted monthly purchased kWh and peak kW produced by the load forecasting model described in Exhibit C-1-1 (Updated) were adjusted for the impact of Conservation and Demand Management activities. The monthly forecasted kWh purchases were multiplied by the monthly forecasted commodity price.

The commodity price for Regulated Price Plan customers ("RPP") was calculated by using the Regulated Price Plan Price Report[2]. The RPP rate of $94.96/MWh was multiplied by a yearly residential factor derived from Ontario's Long-Term Energy Plan[3] ("LTAP") to arrive at a yearly RPP commodity rate for 2016 through 2020. Please see table 2.

Table 2 - Estimated RPP Price 2016 to 2020 (kWh)

2015	2016	2017	2018	2019	2020
0.09496	0.09789	0.09965	0.10434	0.10375	0.10610

[2] Regulated Price Plan: Price Report November 1, 2014 to October 31, 2015, Ontario Energy Board, October 16, 2014
[3] Achieving Balance Ontario's Long-Term Energy Plan, December 3013

The commodity price for non-Regulated Price Plan customers ("non-RPP") was calculated using the Ontario Wholesale Electricity Market Price Forecast[4]. The quarterly rates provided in 'Table ES-1: HOEP Forecast' were used to calculate a 2015 calendar average rate of $20.84/MWh. This rate was multiplied by a commercial factor derived from LTAP to arrive at a yearly rate for 2016 through 2020. Please see table 3.

Table 3 - Estimated HOEP 2016 to 2020 (kWh)

2015	2016	2017	2018	2019	2020
0.02084	0.02174	0.02265	0.02378	0.02310	0.02355

The Wholesale Market Charge is determined from the total kWh purchased multiply by the average rate from 2015 of $0.0057 for all years.

The forecasted kW monthly coincident peak is multiplied by historic percentages for each transmission charge to establish the kWs for those charges. The results are then multiplied by the 2015 rates for all years.

The Global Adjustment is calculated using the Regulated Price Plan Price Report[5]. The Global Adjustment rate of $74.88/MWh was multiplied it by the commercial factor derived from LTAP to arrive at a yearly Global Adjustment rate for 2016 through 2020. Please see table 4. This forecasted rate is multiplied by the Non Regulated Purchase Plan loss adjusted kWh.

Table 4 - Estimated Global Adjustment 2016 to 2020 (kWh)

2015	2016	2017	2018	2019	2020
0.07488	0.07814	0.08139	0.08546	0.08302	0.08465

[4] Ontario Wholesale Electricity Market Price Forecast For the Period November 1, 2014 through April 30, 2016, Navigant Consulting Ltd., October 8, 2014
[5] Regulated Price Plan: Price Report November 1, 2014 to October 31, 2015, Ontario Energy Board, October 16, 2014

From January 1, 2016 to October 31, 2018, the Smart Metering Entity charge of $0.788/ Residential and General Service <50kW customer is included in the calculation of the Cost of Power.

Power Supply Expenses was adjusted to reflect the Low Voltage Switchgear credit which Hydro Ottawa receives as a result of owning the low voltage switchgear at certain stations.

Spreadsheets showing the calculation of the Power Supply Expenses for 2016 through 2020 are provided as attachment B-3(A) COP 2016-2020.

File Number:	EB-2015-0004
Exhibit:	B
Tab:	5
Schedule:	1
Page:	1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-AA
Capital Projects Table

Projects	2011	2012	2013	~~2014 Q2~~	2014 Actual	2015 Bridge Year	2016 Test Year
Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**~~MIFRS~~**	**MIFRS**	**MIFRS**	**MIFRS**
SYSTEM ACCESS							
Plant Relocation	7,743	5,942	10,005	~~9,437~~	9,207	7,814	7,620
Residential	7,247	6,278	6,573	~~5,985~~	5,080	6,720	6,889
Commercial	9,159	11,892	10,634	~~9,342~~	7,289	12,279	13,423
System Expansion	3,276	1,675	5,710	~~10,144~~	9,464	3,727	3,479
Stations Embedded Generation	190	1,181	64	~~277~~	259	376	377
Infill & Upgrade (App. G)	3,081	2,731	3,178	~~2,857~~	3,291	3,075	3,160
Damage to Plant	826	798	1,349	~~840~~	870	1,120	1,148
Metering	112	370	160	~~130~~	81	163	167
Sub-Total	31,635	30,868	37,675	~~39,010~~	35,541	35,275	36,263
SYSTEM RENEWAL							
Stations Asset	5,097	8,475	9,154	~~14,493~~	13,327	17,200	16,338
Stations Refurbishment	2,046	1,067	906	~~825~~	815	679	597
Distribution Asset	20,502	19,698	18,992	~~21,263~~	22,898	21,756	23,683
Metering	122	385	488	~~416~~	369	412	415
Sub-Total	27,768	29,625	29,540	~~36,997~~	37,409	40,048	41,033
SYSTEM SERVICE							
Station Capacity	19,170	11,838	13,198	~~6,223~~	4,352	2,187	5,676
Distribution Enhancements	6,226	8,375	10,319	~~14,961~~	14,587	15,176	11,290
Automation	1,320	1,150	400	~~569~~	359	3,444	5,269
Sub-Total	26,716	21,362	23,917	~~21,753~~	19,298	20,806	22,235
GENERAL PLANT							
Buildings - Facilities	767	380	380	~~426~~	534	688	688
Customer Service	3,818	10,365	13,389	~~5,839~~	5,407	2,450	3,740
ERP System	950	933	478	~~329~~	38	1,547	5,043
Fleet Replacement	2,024	2,542	3,056	~~1,441~~	1,278	1,537	1,455
Info Serv & Tech New Initiatives	296	578	57	~~1,584~~	1,204	2,111	2,127
IT Life Cycle & Ongoing Enhanceme	1,122	2,440	3,076	~~2,821~~	2,879	1,970	1,424
Operations Initiatives	356	683	242	~~3,011~~	2,946	2,756	1,074
Tools Replacements	580	568	539	~~386~~	319	512	512
Hydro One Payments	0	1,116	6,358	~~2,453~~	17,682	2,347	4,575
Facilities Implementation Plan	302	7,586	12,909	~~453~~	468	4,933	25,262
Sub-Total	10,215	27,190	40,484	~~18,742~~	32,755	20,850	45,899
Miscellaneous							
Total	**96,333**	**109,046**	**131,615**	**~~116,503~~**	**125,003**	**116,979**	**145,429**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*							
Total	**96,333**	**109,046**	**131,615**	**~~116,503~~**	**125,003**	**116,979**	**145,429**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.

File Number:	EB-2015-0004
Exhibit:	B
Tab:	5
Schedule:	1
Page:	1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2016*

CATEGORY	Historical Period (previous plan[1] & actual)																	Forecast Period (planned)				
	2011			2012			2013			~~2014 Q2~~			2014 Actual			2015			2016	2017	2018	2019	2020
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	~~Plan~~	~~Actual~~	~~Var~~	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000 000		%	*$ '000 000*		%	*$ '000 000*		%	*~~$ '000 000~~*		~~%~~	*$ '000 000*		%	*$ '000 000*		%	*$ '000 000*				
System Access	30.2	31.6	4.6%	34.5	30.9	-10.4%	36.9	37.7	2.2%	~~40.7~~	~~39.0~~	~~-4.2%~~	40.7	35.5	-12.8%	35.3		-100.0%	36.3	35.2	35.1	35.8	36.6
System Renewal	26.7	27.8	4.1%	27.4	29.6	8.0%	23.4	29.5	26.1%	~~32.8~~	~~37.0~~	~~12.8%~~	32.8	37.4	14.0%	40.0		-100.0%	41.0	31.8	36.5	36.0	35.7
System Service	25.5	26.7	4.7%	21.5	21.4	-0.5%	25.1	23.9	-4.8%	~~23.1~~	~~21.8~~	~~-5.6%~~	23.1	19.3	-16.5%	20.8		-100.0%	22.2	34.0	29.5	30.5	33.3
General Plant	20.6	10.2	-50.5%	35.9	27.2	-24.2%	43.6	40.5	-7.1%	~~22.8~~	~~18.7~~	~~-18.0%~~	22.8	32.8	43.9%	20.9		-100.0%	45.9	48.1	18.3	18.7	14.0
TOTAL EXPENDITURE	103.0	96.3	-6.5%	119.3	109.1	-8.5%	129.0	131.6	2.0%	~~119.4~~	~~116.5~~	~~-2.4%~~	119.4	125.0	4.7%	117.0	-	-100.0%	145.4	149.1	119.4	121.0	119.6
System O&M	N/A	N/A	--	N/A	$ 24.9	--	N/A	$ 25.2	--	~~N/A~~	~~$ 27.1~~	~~--~~	N/A	$ 27.3		$ 29.5	N/A	--	$ 30.9	N/A	N/A	N/A	N/A

Notes to the Table:
1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

See section 3.4 of the DSP (B-1-2)

Notes on year over year Plan vs. Actual variances for Total Expenditures

See section 3.4 of the DSP (B-1-2)

Notes on Plan vs. Actual variance trends for individual expenditure categories

See section 3.4 of the DSP (B-1-2)

File Number:	EB-2015-0004
Exhibit:	B
Tab:	5
Schedule:	3
Page:	1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2012 Historical Year	2013 Historical Year	~~2014 Q2 Forecast~~ ~~Historical Year~~	2014 Historical Year	2015 Bridge Year	2016 Test Year
Collections, Acct & Activities	$ 2,937,418	$ 4,070,580	~~$ 3,649,114~~	$ 3,694,025	$ 3,543,341	$ 4,059,282
Corporate Costs	$ 6,056,030	$ 6,575,378	~~$ 5,420,096~~	$ 7,346,979	$ 5,015,524	$ 4,993,415
Customer & Community Relations	$ 7,716,112	$ 7,605,947	~~$ 8,220,736~~	$ 7,462,160	$ 8,785,231	$ 9,084,617
Customer Billing	$ 9,176,802	$ 9,736,344	~~$ 10,664,787~~	$ 10,604,888	$ 10,432,583	$ 10,511,497
Distribution Operations	$ 33,380,038	$ 34,860,050	~~$ 37,834,129~~	$ 38,425,861	$ 39,785,778	$ 40,824,588
Engineering & Design	$ 10,863,198	$ 11,693,463	~~$ 12,451,538~~	$ 11,921,811	$ 12,975,442	$ 13,677,111
Facilities	$ 5,518,926	$ 5,656,285	~~$ 5,794,592~~	$ 5,763,134	$ 6,027,819	$ 6,108,573
Finance	$ 4,074,222	$ 3,988,437	~~$ 4,368,115~~	$ 4,021,373	$ 4,517,544	$ 4,759,915
Human Resources & Training	$ 3,395,830	$ 3,675,121	~~$ 4,010,176~~	$ 3,590,638	$ 4,051,662	$ 4,180,257
Information Mgt & Technology	$ 6,343,145	$ 6,717,794	~~$ 7,521,460~~	$ 7,459,920	$ 7,500,528	$ 7,862,963
Metering	$ 2,712,295	$ 2,807,318	~~$ 2,846,087~~	$ 2,869,959	$ 2,842,465	$ 2,956,322
Regulatory Affairs	$ 1,930,844	$ 1,967,875	~~$ 2,340,940~~	$ 2,045,915	$ 2,505,096	$ 2,580,684
Safety, Environment & Bus Cont	$ 1,853,905	$ 2,334,564	~~$ 2,116,845~~	$ 2,129,401	$ 1,952,732	$ 2,006,305
Supply Chain	$ 2,233,136	$ 1,985,925	~~$ 2,491,808~~	$ 2,327,632	$ 2,498,434	$ 2,744,524
Total OM&A Before Capitalization (B)	$ 98,191,900	$ 103,675,081	~~$ 109,730,424~~	$ 109,663,695	$ 112,434,180	$ 116,350,054

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2012 Historical Year	2013 Historical Year	~~2014 Q2 Forecast~~ ~~Historical Year~~	2014 Historical Year	2015 Bridge Year	2016 Test Year	Directly Attributable? (Y/N)	Explanation for Change in Overhead Capitalized
Supply Chain	$ 1,127,115	$ 1,305,256	~~$ 1,301,156~~	$ 1,143,039	$ 1,244,923	$ 1,452,331		
Supervision	$ 1,831,800	$ 2,157,288	~~$ 1,826,399~~	$ 1,800,435	$ 2,034,276	$ 2,077,315		
Engineering	$ 1,996,465	$ 2,815,805	~~$ 2,843,934~~	$ 2,638,519	$ 2,904,091	$ 2,997,522		
Fleet	$ 2,613,093	$ 2,593,457	~~$ 2,737,548~~	$ 2,718,734	$ 2,627,424	$ 2,698,352		
Labour	$ 17,547,092	$ 19,046,118	~~$ 20,253,970~~	$ 20,453,974	$ 19,967,657	$ 20,018,970		
Total Capitalized OM&A (A)	$ 25,115,566	$ 27,917,925	~~$ 28,963,007~~	$ 28,754,700	$ 28,778,371	$ 29,244,490		

% of Capitalized OM&A (=A/B)	26%	27%	~~26%~~	26%	26%	25%		

LOAD FORECAST

Hydro Ottawa Limited ("Hydro Ottawa") engaged Itron to complete a 2015 to 2020 sales and energy forecast. Itron completed forecasts for total purchases sales and system demand and rate class sales, customers and connections, and billing demand. The forecast utilized actual data on sales, customer numbers and connections, and purchases until August 2014. Forecasts were provided both with and without the impact of future Conservation Demand Management ("CDM") targets.

A Purchases model was used with total sales allocated to the rate class sales forecast. For details regarding the forecast methodology, including CDM persistence and future targets, economic assumption, and data sources please see Itron's report as C-1(A).

Hydro Ottawa has completed Appendix 2-I, Load Forecast CDM Adjustment Workbook (2015) and Appendix 2-IA (Updated) Summary and Variances of Actual and Forecast Data, and can be found as PDFs at the end of this exhibit.

While completing the Load Forecast, Hydro Ottawa was performing its analysis for its rate reclassification. Based on a detailed customer level analysis of the impact of the rate reclassification, Hydro Ottawa has adjusted the class level load forecast and customer numbers developed by Itron. The total kWh sales, kW demand, and customer and connection numbers equal that of Itron's, however the class level forecasts are different; the main reclassification being between General Service < 50 kW and General Service > 50 kW classifications. With new procedures implemented Hydro Ottawa is anticipating less movement between the General Service classes in the future.

Hydro Ottawa has also adjusted the forecast to include Sentinel Lights and Standby Demand as these were not forecasted separately by Itron.

Table 1 provides Hydro Ottawa's Sales forecast by MWh for 2016 through 2020.

Table 1 – Hydro Ottawa 2016 through 2020 Forecasted Sales Forecast (MWh) by class[1]

	2016	2017	2018	2019	2020
RESIDENTIAL	2,216,045	2,198,259	2,206,411	2,214,984	2,217,628
GENERAL SERVICE <50KW	726,360	716,896	709,791	704,193	699,744
GENERAL SERVICE 50-1000KW Non Interval	1,386,977	1,336,827	1,295,564	1,259,397	1,226,514
GENERAL SERVICE 50-1000KW Interval	1,207,946	1,214,762	1,226,094	1,240,552	1,256,773
GENERAL SERVICE 1000-1500KW	359,518	355,856	353,764	352,644	352,100
GENERAL SERVICE 1500-5000 KW	863,309	877,400	895,369	914,569	935,554
LARGE USER	620,218	619,253	618,467	617,036	615,195
STREETLIGHTING	43,552	43,653	43,765	43,876	44,015
MU	16,651	16,690	16,731	16,772	16,827
SENTINEL LIGHTS	48	48	48	48	48
TOTAL MWH SALES	7,440,624	7,379,644	7,366,004	7,364,071	7,364,398

Table 2 provides Hydro Ottawa's Demand forecast by kW for 2016 through 2020

[1] Forecat does not include Dry Core Transformer Charge

Table 2 – Hydro Ottawa 2016 through 2020 Demand Forecast (kW) by class

	2016	2017	2018	2019	2020
GENERAL SERVICE 50-1000KW Non Interval	3,533,354	3,406,354	3,301,064	3,208,582	3,123,291
GENERAL SERVICE 50-1000KW Interval	2,725,183	2,740,805	2,766,375	2,798,890	2,835,076
GENERAL SERVICE 1000-1500KW	769,442	761,481	756,911	754,458	753,212
GENERAL SERVICE 1500-5000 KW	1,847,365	1,877,691	1,916,044	1,957,009	2,001,525
STANDBY	4,800	4,800	4,800	4,800	4,800
LARGE USER	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342
STREETLIGHTING	123,144	123,144	123,144	123,144	123,144
SENTINEL LIGHTS	216	216	216	216	216
TOTAL	10,124,953	10,034,217	9,986,854	9,962,801	9,953,606

Table 3 provides Hydro Ottawa's average number of customers and connections forecast for 2016 through 2020.

Table 3 – Hydro Ottawa 2016 through 2020 Average Number of Customers and Connections by class

	2016	2017	2018	2019	2020
RESIDENTIAL	297,343	301,258	305,144	308,990	312,786
GENERAL SERVICE <50KW	24,512	24,626	24,739	24,850	24,959
GENERAL SERVICE 50-1000KW NONI	2,481	2,481	2,481	2,481	2,481
GENERAL SERVICE 50-1000KW INT	758	785	813	841	869
GENERAL SERVICE 1000-1500KW	57	57	57	58	58
GENERAL SERVICE 1500-5000 KW	76	76	76	76	76
STANDBY	2	2	2	2	2
LARGE USERS	11	11	11	11	11
TOTAL CUSTOMERS	325,240	329,296	333,323	337,308	341,243

	2016	2017	2018	2019	2020
STREET LIGHTING	55,516	55,516	55,516	55,516	55,516
SENTINEL LIGHTS	55	51	47	43	39
UNMETERED SCATTERED LOADS	3,477	3,525	3,573	3,621	3,669
TOTAL CONNECTIONS	59,048	59,092	59,136	59,180	59,224

Table 4 provides Hydro Ottawa's forecast kW for 2016 through 2020 for the transformer ownership credit.

Table 4 – Hydro Ottawa 2016 through 2020 Demand Forecast (kW) for Transformer Ownership Credit

	2016	2017	2018	2019	2020
GENERAL SERVICE 50-1000KW NONI	(883,339)	(851,589)	(825,266)	(802,146)	(780,823)
GENERAL SERVICE 50-1000KW INT	(681,296)	(685,201)	(691,594)	(699,723)	(708,769)
GENERAL SERVICE 1000-1500KW	(192,361)	(190,370)	(189,228)	(188,615)	(188,303)
GENERAL SERVICE 1500-5000 KW	(461,841)	(469,423)	(479,011)	(489,252)	(500,381)
LARGE USER	(280,362)	(279,932)	(279,575)	(278,926)	(278,086)
TOTAL CUSTOMERS	(2,499,198)	(2,476,514)	(2,464,674)	(2,458,660)	(2,456,362)

For class level revenue forecast please see Appendix 2-V, Revenue Reconciliation.

ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSES

1.0 INTRODUCTION

Hydro Ottawa Limited's ("Hydro Ottawa") last rebasing year was 2012. Hydro Ottawa has not completed a detailed load forecast since this rebasing given that Hydro Ottawa has increased rates based on an Incentive Regulation Model ("IRM") for the years 2013 to 2015. As such, Hydro Ottawa felt it was financially prudent not to invest in preparing a detailed load forecast for the years in which rates would not be set by the forecast.

2.0 HISTORICAL ACCURACY OF LOAD FORECAST

Given Hydro Ottawa has not completed a load forecast since 2012 it can only compare the 2012 Board Approved load forecast to the actual sales and demand results and customer count and connects for that year.

Hydro Ottawa has completed Appendix 2-IA (Updated), Summary and Variances of Actual and Forecast Data, which provides a schedule of volumes, customer count and connects by rate class including total system load. This also includes a comparison of historical board-approved versus historical actual. Appendix 2-IA (Updated) is provided as an attachment to this exhibit. Per Appendix 2-IA (Updated):

- Actual 2012 kWhs were 1.36% less than the Board approved forecast;
- Actual 2012 kWs were 0.61% less than the Board approved forecasts;
- Customer count and connects was within 0.01% of Boards approved forecast, customer counts and connection as the average for that year.

Hydro Ottawa has added a total variance year over year comparison to the bottom of Appendix 2-IA (Updated). 2015 to 2020 data is weather normalized. For details regarding the class level assumptions and data sources, please refer to Itron's load forecast report available in Attachment C-1(A) to exhibit C-1-1 (Updated),

Hydro Ottawa has utilized the format of Appendix 2-IA (Updated), please see attachment C-1(B) (Updated),

to provide the following comparisons:

- Historical Board-approved vs. Historical Actual – weather normalized;
- Historical Actual – weather-normalized vs. preceding year's Historical Actual – weather-normalized (for the necessary number of years);
- Historical Actual – weather normalized vs. Bridge Year – weather-normalized; and
- Bridge Year – weather-normalized vs. Test Year.

Hydro Ottawa has confidence that the variances between the afore-mentioned analyses are within an acceptable tolerance.

Itron's 2016-2020 load forecast and data are available in excel format as attachment C-1(C) to C-1(L)

File Number:	EB-2015-0004
Exhibit:	C
Tab:	1
Schedule:	2
Page:	
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-IA
Summary and Variances of Actual and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

	2012 Board Approved	2012	2013	2014 Forecast	2014	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test	2012 Board Approved vs Actual
RESIDENTIAL												
# of Customers	280,901	280,254	284,964	284,296	289,385	293,366	297,343	301,258	305,144	308,990	312,786	647
kWh	2,282,535,398	2,302,188,900	2,256,501,094	2,287,520,580	2,241,029,046	2,233,419,000	2,216,045,000	2,198,259,000	2,206,411,000	2,214,984,000	2,217,628,000	- 19,653,502
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis												
# of Customers		-0.23%	1.45%	1.21%	3.02%	4.44%	5.85%	7.25%	8.63%	10.00%	11.35%	
kWh		0.86%	-1.14%	0.22%	-1.82%	-2.15%	-2.91%	-3.69%	-3.34%	-2.96%	-2.84%	
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
GENERAL SERVICE <50KW												
# of Customers	23,636	23,767	23,936	23,817	23,968	24,099	24,512	24,626	24,739	24,850	24,959	- 131
kWh	770,026,295	702,625,952	720,479,340	746,537,340	714,938,854	705,279,000	726,360,000	716,896,000	709,791,000	704,193,000	699,744,000	67,400,343
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis												
# of Customers		0.55%	1.27%	0.77%	1.40%	1.96%	3.71%	4.19%	4.67%	5.14%	5.60%	
kWh		-8.75%	-6.43%	-3.05%	-7.15%	-8.41%	-5.67%	-6.90%	-7.82%	-8.55%	-9.13%	
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
GENERAL SERVICE 50-1999KW												
# of Customers	3,340	3,416	3,408	3,417	3,514	3,549	3,296	3,323	3,351	3,380	3,408	- 76
kWh	3,051,141,934	2,982,426,722	3,006,131,060	3,052,417,630	2,925,639,578	2,957,727,000	2,954,441,000	2,907,445,000	2,875,422,000	2,852,593,000	2,835,387,000	68,715,212
kW	7,404,278	7,288,884	7,292,973	7,621,504	7,052,272	7,070,781	7,027,979	6,908,640	6,824,350	6,761,930	6,711,579	N/A
Variance Analysis												
# of Customers		2.28%	2.04%	2.31%	5.21%	6.26%	-1.32%	-0.51%	0.33%	1.20%	2.04%	
kWh		-2.25%	-1.48%	0.04%	-4.11%	-3.06%	-3.17%	-4.71%	-5.76%	-6.51%	-7.07%	
kW		-1.56%	-1.50%	2.93%	-4.75%	-4.50%	-5.08%	-6.69%	-7.83%	-8.68%	-9.36%	
GENERAL SERVICE 1500-5000 KW												
# of Customers	71	74	76	72	87	88	76	76	76	76	76	- 3
kWh	836,317,557	870,903,316	857,551,218	840,571,690	872,269,484	883,242,000	863,309,000	877,400,000	895,369,000	914,569,000	935,554,000	- 34,585,759
kW	1,719,678	1,864,369	1,866,871	1,809,214	1,874,998	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562	N/A
Variance Analysis												
# of Customers		4.23%	7.04%	1.41%	22.54%	23.94%	7.04%	7.04%	7.04%	7.04%	7.04%	
kWh		4.14%	2.54%	0.51%	4.30%	5.61%	3.23%	4.91%	7.06%	9.36%	11.87%	
kW		8.41%	8.56%	5.21%	9.03%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%	
LARGE USER												
# of Customers	11	11	11	11	11	11	11	11	11	11	11	-
kWh	672,395,178	646,432,433	613,513,830	653,609,490	607,320,659	620,305,000	620,218,000	619,253,000	618,467,000	617,036,000	615,195,000	25,962,745
kW	1,187,623	1,178,836	1,135,342	1,195,741	1,117,860	1,121,629	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342	N/A
Variance Analysis												
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kWh		-3.86%	-8.76%	-2.79%	-9.68%	-7.75%	-7.76%	-7.90%	-8.02%	-8.23%	-8.51%	
kW		-0.74%	-4.40%	0.68%	-5.87%	-5.56%	-5.57%	-5.72%	-5.84%	-6.06%	-6.34%	
STREETLIGHTING												
# of Connections	55,546	55,674	55,757	56,608	55,524	55,516	55,516	55,516	55,516	55,516	55,516	- 128
kWh	41,153,239	44,699,159	44,767,415	43,962,170	44,363,900	43,501,000	43,552,000	43,653,000	43,765,000	43,876,000	44,015,000	- 3,545,920
kW	121,500	123,332	123,947	129,682	122,870	123,144	123,144	123,144	123,144	123,144	123,144	N/A
Variance Analysis												
# of Connections		0.23%	0.38%	1.91%	-0.04%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%	
kWh		8.62%	8.78%	6.83%	7.80%	5.70%	5.83%	6.07%	6.35%	6.62%	6.95%	
kW		1.51%	2.01%	6.73%	1.13%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%	
UMSL												
# of Connections	3,093	3,384	3,376	3,333	3,438	3,444	3,477	3,525	3,573	3,621	3,669	- 291
kWh	17,394,983	17,594,132	17,054,550	16,739,310	16,412,499	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000	- 199,149
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis												
# of Connections		9.41%	9.15%	7.76%	11.15%	11.35%	12.42%	13.97%	15.52%	17.07%	18.62%	
kWh		1.14%	-1.96%	-3.77%	-5.65%	-4.28%	-4.28%	-4.28%	-4.28%	-4.28%	-4.28%	
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
SENTINEL LIGHTS												
# of Connections	N/A	61	57	78	57	57	55	51	47	43	39	N/A
kWh	N/A	59,894	49,020	-	50,344	48,000	48,000	48,000	48,000	48,000	48,000	N/A
kW	221	166	139	-	175	216	216	216	216	216	216	N/A
Variance Analysis												
# of Connections		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kW		-24.89%	-37.10%	-100.00%	-20.72%	-2.26%	-2.26%	-2.26%	-2.26%	-2.26%	-2.26%	
STANDBY												
# of Customers	N/A	2	2	2	2	2	2	2	2	2	2	N/A
kWh	N/A											N/A
kW	86,400	Included in actuals for class		4,800	Included in class	4,800	4,800	4,800	4,800	4,800	4,800	N/A
Variance Analysis												
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kW		0.00%	-100.00%	-94.44%	0.00%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%	
Rate Class 10												
# of Customers												
kWh												
kW												
Variance Analysis												
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Totals												
Customers / Connections	366,598	366,643	371,587	371,634	375,986	380,132	384,288	388,388	392,459	396,489	400,466	18
kWh	7,670,964,584	7,566,930,508	7,516,047,527	7,641,358,210	7,422,024,364	7,460,172,000	7,440,624,000	7,379,605,000	7,365,924,000	7,363,950,000	7,364,222,000	104,093,970
kW from applicable classes	10,519,700	10,455,587	10,419,272	10,760,940	10,168,175	10,206,132	10,163,150	10,042,088	9,956,372	9,891,354	9,837,643	-
Totals - Variance												
Customers / Connections		0.01%	1.36%	1.37%	2.56%	3.69%	4.83%	5.94%	7.05%	8.15%	9.24%	
kWh		-1.36%	-2.02%	-0.39%	-3.25%	-2.75%	-3.00%	-3.80%	-3.98%	-4.00%	-4.00%	
kW from applicable classes		-0.61%	-0.95%	2.29%	-3.34%	-2.98%	-3.39%	-4.54%	-5.35%	-5.97%	-6.48%	
Totals - Variance Year over Year					2015 to 2014 Forcast							
Customers / Connections		0.01%	1.35%	0.01%	1.18%	2.29%	1.09%	1.07%	1.05%	1.03%	1.00%	
kWh		-1.36%	-0.67%	1.67%	-1.25%	-2.37%	-0.26%	-0.82%	-0.19%	-0.03%	0.00%	
kW from applicable classes		-0.61%	-0.35%	3.28%	-2.41%	-5.16%	-0.42%	-1.19%	-0.85%	-0.65%	-0.54%	

2015 to 2014
1.10%
0.51%
0.37%

Summary and Variances of Weather Normalized Actuals to 2012 Board Approved (Updated)

Replace "Rate Class #" with the appropriate rate classification.

	2010 Weather Normalized	2011 Weather Normalized	2012 Board Approved	2012 Weather Normalized	2013 Weather Normalized	2014 Forecast Weather Normalized	2014 Weather Normalized	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test
RESIDENTIAL													
# of Customers	271,603	275,966	280,901	280,254	284,964	284,296	289,385	293,366	297,343	301,258	305,144	308,990	312,786
kWh	2,267,082,000	2,249,645,000	2,282,535,398	2,255,121,000	2,252,988,000	2,267,127,000	2,265,758,000	2,233,419,000	2,216,045,000	2,198,259,000	2,206,411,000	2,214,984,000	2,217,628,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis													
# of Customers	-3.31%	-1.76%		-0.23%	1.45%	1.21%	3.02%	4.44%	5.85%	7.25%	8.63%	10.00%	11.35%
kWh	-0.68%	-1.44%		-1.20%	-1.29%	-0.68%	-0.74%	-2.15%	-2.91%	-3.69%	-3.34%	-2.96%	-2.84%
kW	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENERAL SERVICE <50KW													
# of Customers	23,434	23,616	23,636	23,767	23,936	23,817	23,968	24,099	24,512	24,626	24,739	24,850	24,959
kWh	731,617,000	723,597,000	770,026,295	719,380,000	721,817,000	707,782,000	703,782,000	705,279,000	726,360,000	716,896,000	709,791,000	704,193,000	699,744,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis													
# of Customers	-0.85%	-0.08%		0.55%	1.27%	0.77%	1.40%	1.96%	3.71%	4.19%	4.67%	5.14%	5.60%
kWh	-4.99%	-6.03%		-6.58%	-6.26%	-8.08%	-8.60%	-8.41%	-5.67%	-6.90%	-7.82%	-8.55%	-9.13%
kW	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENERAL SERVICE 50-1499KW													
# of Customers	3,279	3,353	3,340	3,416	3,408	3,417	3,514	3,549	3,296	3,323	3,351	3,380	3,408
kWh	3,026,694,000	3,035,733,000	3,051,141,934	3,017,363,000	2,981,441,000	2,970,045,000	2,944,426,000	2,957,727,000	2,954,441,000	2,907,445,000	2,875,422,000	2,852,593,000	2,835,387,000
kW	7,272,741	7,290,048	7,404,278	7,234,407	7,143,842	7,104,743	7,047,025	7,070,781	7,027,979	6,908,640	6,824,350	6,761,930	6,711,579
Variance Analysis													
# of Customers	-1.83%	0.39%		2.28%	2.04%	2.31%	5.21%	6.26%	-1.32%	-0.51%	0.33%	1.20%	2.04%
kWh	-0.80%	-0.51%		-1.11%	-2.28%	-2.66%	-3.50%	-3.06%	-3.17%	-4.71%	-5.76%	-6.51%	-7.07%
kW	-1.78%	-1.54%		-2.29%	-3.52%	-4.05%	-4.82%	-4.50%	-5.08%	-6.69%	-7.83%	-8.68%	-9.36%
GENERAL SERVICE 1500-5000 KW													
# of Customers	66	69	71	74	76	72	87	88	76	76	76	76	76
kWh	827,600,000	855,055,000	836,317,557	865,127,000	860,146,000	864,262,000	874,304,000	883,242,000	863,309,000	877,400,000	895,369,000	914,569,000	935,554,000
kW	1,766,012	1,825,276	1,719,678	1,845,437	1,836,496	1,856,692	1,867,028	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562
Variance Analysis													
# of Customers	-6.92%	-2.23%		4.23%	7.04%	1.41%	22.54%	23.94%	7.04%	7.04%	7.04%	7.04%	7.04%
kWh	-1.04%	2.24%		3.44%	2.85%	3.34%	4.54%	5.61%	3.23%	4.91%	7.06%	9.36%	11.87%
kW	2.69%	6.14%		7.31%	6.79%	7.97%	8.57%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%
LARGE USER													
# of Customers	12	11	11	11	11	11	11	11	11	11	11	11	11
kWh	683,012,000	659,208,000	672,395,178	641,537,000	628,405,000	617,273,000	611,016,000	620,305,000	620,218,000	619,253,000	618,467,000	617,036,000	615,195,000
kW	1,234,876	1,191,286	1,187,623	1,158,988	1,137,277	1,115,729	1,105,052	1,121,629	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342
Variance Analysis													
# of Customers	9.09%	0.76%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	1.58%	-1.96%		-4.59%	-6.54%	-8.20%	-9.13%	-7.75%	-7.76%	-7.90%	-8.02%	-8.23%	-8.51%
kW	3.98%	0.31%		-2.41%	-4.24%	-6.05%	-6.95%	-5.56%	-5.57%	-5.72%	-5.84%	-6.06%	-6.34%
STREETLIGHTING													
# of Connections	54,395	54,679	55,546	55,674	55,757	56,608	55,524	55,516	55,516	55,516	55,516	55,516	55,516
kWh	43,535,000	43,719,000	41,153,239	44,699,000	44,767,000	44,646,000	44,364,000	43,501,000	43,552,000	43,653,000	43,765,000	43,876,000	44,015,000
kW			121,500	123,332	123,947	129,682	122,870	123,144	123,144	123,144	123,144	123,144	123,144
Variance Analysis													
# of Connections	-2.07%	-1.56%		0.23%	0.38%	1.91%	-0.04%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%	-0.05%
kWh	5.79%	6.23%		8.62%	8.78%	8.49%	7.80%	5.70%	5.83%	6.07%	6.35%	6.62%	6.95%
kW	-100.00%	-100.00%		1.51%	2.01%	6.73%	1.13%	1.35%	1.35%	1.35%	1.35%	1.35%	1.35%
UMSL													
# of Connections	2,907	3,183	3,093	3,384	3,376	3,333	3,438	3,444	3,477	3,525	3,573	3,621	3,669
kWh	17,309,000	18,044,000	17,394,983	17,594,000	17,055,000	16,489,000	16,413,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis													
# of Connections	-6.01%	2.90%		9.41%	9.15%	7.76%	11.15%	11.35%	12.42%	13.97%	15.52%	17.07%	18.62%
kWh	-0.49%	3.73%		1.14%	-1.95%	-5.21%	-5.65%	-4.28%	-4.28%	-4.28%	-4.28%	-4.28%	-4.28%
kW	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SENTINEL LIGHTS													
# of Connections	73	65	N/A	61	57	78	57	57	55	51	47	43	39
kWh	74,233	64,267	N/A	59,894	49,020	Not forecasted	50,344	48,000	48,000	48,000	48,000	48,000	48,000
kW	206	179	221	166	139	Not forecasted	175	216	216	216	216	216	216
Variance Analysis													
# of Connections	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW	-6.79%	-19.00%		-24.89%	-37.10%	0.00%	-20.72%	-2.26%	-2.26%	-2.26%	-2.26%	-2.26%	-2.26%
STANDBY													
# of Customers	2	2	N/A	2	2	2	2	2	2	2	2	2	2
kWh			N/A										
kW	Included in actuals for class		86,400	Included in actuals for class		4,800	Included class	4,800	4,800	4,800	4,800	4,800	4,800
Variance Analysis													
# of Customers	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW	0.00%	-100.00%		0.00%	-100.00%	-94.44%	0.00%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%	-94.44%
Rate Class 10													
# of Customers													
kWh													
kW													
Variance Analysis													
# of Customers	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW	0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Totals

Customers / Connections	355,771	360,945	366,598	366,643	371,587	371,634	375,986	380,132	384,288	388,388	392,459	396,489	400,466
kWh	7,596,923,233	7,585,065,267	7,670,964,584	7,560,880,894	7,506,668,020	7,487,624,000	7,460,113,344	7,460,172,000	7,440,624,000	7,379,605,000	7,365,924,000	7,363,950,000	7,364,222,000
kW from applicable classes	10,273,835	10,306,788	10,519,700	10,362,330	10,241,701	10,211,646	10,142,150	10,206,132	10,163,150	10,042,088	9,956,372	9,891,354	9,837,643

Totals - Variance

Customers / Connections	-2.95%	-1.54%		0.01%	1.36%	1.37%	2.56%	3.69%	4.83%	5.94%	7.05%	8.15%	9.24%
kWh	-0.97%	-1.12%		-1.44%	-2.14%	-2.39%	-2.75%	-2.75%	-3.00%	-3.80%	-3.98%	-4.00%	-4.00%
kW from applicable classes	-2.34%	-2.02%		-1.50%	-2.64%	-2.93%	-3.59%	-2.98%	-3.39%	-4.54%	-5.35%	-5.97%	-6.48%

Totals - Variance Year over Year

								2015 to 2014 Forcast					
Customers / Connections	0.00%	1.45%		0.01%	1.35%	0.01%	1.18%	2.29%	1.09%	1.07%	1.05%	1.03%	1.00%
kWh	0.00%	-0.16%		-1.44%	-0.72%	-0.25%	-0.62%	-0.37%	-0.26%	-0.82%	-0.19%	-0.03%	0.00%
kW from applicable classes	0.00%	0.32%		-1.50%	-1.16%	-0.29%	-0.97%	-0.05%	-0.42%	-1.19%	-0.85%	-0.65%	-0.54%

2015 to 2014
1.10%
0.00%
0.63%

Summary and Variances of Weather Normalized Actuals and Forecast Data

Replace "Rate Class #" with the appropriate rate classification.

	2010 Weather Normalized	2011 Weather Normalized	2012 Weather Normalized	2013 Weather Normalized	2014 Forecast Weather Normalized	2015 Bridge	2016 Test	2017 Test	2018 Test	2019 Test	2020 Test
RESIDENTIAL											
# of Customers	271,603	275,966	280,254	284,964	284,296	293,366	297,343	301,258	305,144	308,990	312,786
kWh	2,267,082,000	2,249,645,000	2,255,121,000	2,252,988,000	2,267,127,000	2,233,419,000	2,216,045,000	2,198,259,000	2,206,411,000	2,214,984,000	2,217,628,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis											
# of Customers		1.61%	1.55%	1.68%	-0.23%	3.19%	1.36%	1.32%	1.29%	1.26%	1.23%
kWh		-0.77%	0.24%	-0.09%	0.63%	-1.49%	-0.78%	-0.80%	0.37%	0.39%	0.12%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENERAL SERVICE <50KW											
# of Customers	23,434	23,616	23,767	23,936	23,817	24,099	24,512	24,626	24,739	24,850	24,959
kWh	731,617,000	723,597,000	719,380,000	721,817,000	707,782,000	705,279,000	726,360,000	716,896,000	709,791,000	704,193,000	699,744,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis											
# of Customers		0.78%	0.64%	0.71%	-0.50%	1.18%	1.71%	0.47%	0.46%	0.45%	0.44%
kWh		-1.10%	-0.58%	0.34%	-1.94%	-0.35%	2.99%	-1.30%	-0.99%	-0.79%	-0.63%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GENERAL SERVICE 50-1499KW											
# of Customers	3,279	3,353	3,416	3,408	3,417	3,549	3,296	3,323	3,351	3,380	3,408
kWh	3,026,694,000	3,035,733,000	3,017,363,000	2,981,441,000	2,970,045,000	2,957,727,000	2,954,441,000	2,907,445,000	2,875,422,000	2,852,593,000	2,835,387,000
kW	7,272,741	7,290,048	7,234,407	7,143,842	7,104,743	7,070,781	7,027,979	6,908,640	6,824,350	6,761,930	6,711,579
Variance Analysis											
# of Customers		2.26%	1.88%	-0.23%	0.26%	3.86%	-7.13%	0.82%	0.84%	0.87%	0.83%
kWh		0.30%	-0.61%	-1.19%	-0.38%	-0.41%	-0.11%	-1.59%	-1.10%	-0.79%	-0.60%
kW		0.24%	-0.76%	-1.25%	-0.55%	-0.48%	-0.61%	-1.70%	-1.22%	-0.91%	-0.74%
GENERAL SERVICE 1500-5000 KW											
# of Customers	66	69	74	76	72	88	76	76	76	76	76
kWh	827,600,000	855,055,000	865,127,000	860,146,000	864,262,000	883,242,000	863,309,000	877,400,000	895,369,000	914,569,000	935,554,000
kW	1,766,012	1,825,276	1,845,437	1,836,496	1,856,692	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562	1,885,562
Variance Analysis											
# of Customers		5.04%	6.60%	2.70%	-5.26%	22.22%	-13.64%	0.00%	0.00%	0.00%	0.00%
kWh		3.32%	1.18%	-0.58%	0.48%	2.20%	-2.26%	1.63%	2.05%	2.14%	2.29%
kW		3.36%	1.10%	-0.48%	1.10%	1.55%	0.00%	0.00%	0.00%	0.00%	0.00%
LARGE USER											
# of Customers	12	11	11	11	11	11	11	11	11	11	11
kWh	683,012,000	659,208,000	641,537,000	628,405,000	617,273,000	620,305,000	620,218,000	619,253,000	618,467,000	617,036,000	615,195,000
kW	1,234,876	1,191,286	1,158,988	1,137,277	1,115,729	1,121,629	1,121,449	1,119,726	1,118,300	1,115,702	1,112,342
Variance Analysis											
# of Customers		-7.64%	-0.75%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		-3.49%	-2.68%	-2.05%	-1.77%	0.49%	-0.01%	-0.16%	-0.13%	-0.23%	-0.30%
kW		-3.53%	-2.71%	-1.87%	-1.89%	0.53%	-0.02%	-0.15%	-0.13%	-0.23%	-0.30%
STREETLIGHTING											
# of Connections	54,395	54,679	55,674	55,757	56,608	55,516	55,516	55,516	55,516	55,516	55,516
kWh	43,535,000	43,719,000	44,699,000	44,767,000	44,646,000	43,501,000	43,552,000	43,653,000	43,765,000	43,876,000	44,015,000
kW			123,332	123,947	129,682	123,144	123,144	123,144	123,144	123,144	123,144
Variance Analysis											
# of Connections		0.52%	1.82%	0.15%	1.53%	-1.93%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.42%	2.24%	0.15%	-0.27%	-2.56%	0.12%	0.23%	0.26%	0.25%	0.32%
kW		0.00%	0.00%	0.50%	4.63%	-5.04%	0.00%	0.00%	0.00%	0.00%	0.00%
UMSL											
# of Connections	2,907	3,183	3,384	3,376	3,333	3,444	3,477	3,525	3,573	3,621	3,669
kWh	17,309,000	18,044,000	17,594,000	17,055,000	16,489,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000	16,651,000
kW	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Variance Analysis											
# of Connections		9.48%	6.33%	-0.24%	-1.27%	3.33%	0.96%	1.38%	1.36%	1.34%	1.33%
kWh		4.25%	-2.49%	-3.06%	-3.32%	0.98%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SENTINEL LIGHTS											
# of Connections	73	65	61	57	78	57	55	51	47	43	39
kWh	74,233	64,267	59,894	49,020	Not forecasted	48,000	48,000	48,000	48,000	48,000	48,000
kW	206	179	166	139	Not forecasted	216	216	216	216	216	216
Variance Analysis											
# of Connections		-10.96%	-6.15%	-6.56%	36.84%	-26.92%	-3.51%	-7.27%	-7.84%	-8.51%	-9.30%
kWh		-13.43%	-6.80%	-18.16%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		-13.11%	-7.26%	-16.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
STANDBY											
# of Customers	2	2	2	2	2	2	2	2	2	2	2
kWh											
kW	Included in actuals for class		Included in actuals for class		4,800	4,800	4,800	4,800	4,800	4,800	4,800
Variance Analysis											
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate Class 10											
# of Customers											
kWh											
kW											
Variance Analysis											
# of Customers		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kWh		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
kW		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Totals

Customers / Connections	355,771	360,945	366,643	371,587	371,634	380,132	384,288	388,388	392,459	396,489	400,466
kWh	7,596,923,233	7,585,065,267	7,560,880,894	7,506,668,020	7,487,624,000	7,460,172,000	7,440,624,000	7,379,605,000	7,365,924,000	7,363,950,000	7,364,222,000
kW from applicable classes	10,273,835	10,306,788	10,362,330	10,241,701	10,211,646	10,206,132	10,163,150	10,042,088	9,956,372	9,891,354	9,837,643

Totals - Variance

Customers / Connections	0.00%	-0.16%	-0.32%	-0.72%	-0.25%	-0.37%	-0.26%	-0.82%	-0.19%	-0.03%	0.00%
kWh	0.00%	0.32%	0.54%	-1.16%	-0.29%	-0.05%	-0.42%	-1.19%	-0.85%	-0.65%	-0.54%
kW from applicable classes	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

OTHER REVENUE SUMMARY

1.0 INTRODUCTION

Other Revenue, also referred to as Revenue Offsets, relates to all utility revenues other than distribution and cost of power revenues. Hydro Ottawa Limited ("Hydro Ottawa") has classified these into the following categories: Specific Service Charges, Late Payment Charges, Other Operating Revenue and Other Income and Deductions. Table 1, below, provides a summary of Other Revenue from 2012 through 2016, along with the associated Uniform System of Accounts ("USofA"), rounded to the nearest $1,000.

Table 1 - Other Revenue Summary

Other Revenue	2012 Actual $000	2013 Actual $000	~~2014 Budget $000~~	2014 Actual $000	2015 Forecast $000	2016 Forecast $000
Specific Service Charges (4235)	3,583	5,293	~~3,801~~	4,272	3,710	5,910
Late Payment Charges (4225)	872	907	~~956~~	846	899	899
Other Operating Revenue (4082, 4084, 4086, 4090)	1,197	1,004	~~1,064~~	1,067	925	1,411
Other Income & Deductions (4315, 4320, 4325, 4330, 4355, 4360, 4362, 4375, 4405)	2,303	1,777	~~3,163~~	3,251	3,313	3,480
Total Other Revenue	**7,955**	**8,980**	**~~8,984~~**	**9,436**	**8,847**	**11,700**

A detailed breakdown of Other Operating Revenue and Other Income and Deductions is provided in Appendix 2-H.

2.0 SPECIFIC SERVICE CHARGES

A specific service charge is applied for service requests or activities which primarily benefit or are attributed to the customer who requests or initiates the specific service or activity. Some specific service charges are applied as a result of a customer's inaction.

As noted in Exhibit H-7-1, Hydro Ottawa undertook a review of many routine service charges to ensure that the associated costs of providing such services were appropriately recovered.

With the exception of six (6) previously approved specific service charges, Hydro Ottawa is proposing to increase or introduce new specific service charges ("service charges") for the years 2016 through 2020.

3.0 LATE PAYMENT CHARGES

An OEB-approved monthly interest rate of 1.5% (19.56 per annum) is applied to outstanding account balances that exceed sixteen calendar days from the date a bill is mailed.

4.0 OTHER OPERATING REVENUES

Other Operating Revenues include revenue associated from the provision of Standard Supply, Retailer and Generator services.

Generator service revenue was historically recorded under Other Income and Deductions (4325); however, as of 2016 the associated revenues shall be recorded in (4090), as part of Other Operating Revenues.

The service charges associated with these services are proposed to increase in 2016 through 2020.

5.0 OTHER INCOME AND DEDUCTIONS

Hydro Ottawa also earns revenue through the provision of services to customers and third parties, rental income from leased plant, gains (or losses) on the disposal or

retirement of utility property, the provision of services to Hydro Ottawa's affiliates and the City of Ottawa, as well as, earning interest income on short-term investments.

5.1 Works for Others

5.1.1 Services to the City of Ottawa

In addition to the sale of electricity, Hydro Ottawa rents poles and ducts to the City of Ottawa, as well as, performs minor routine work. Revenue associated with pole attachments is recorded under Service Charge revenue. Duct rental revenue is part of Other Income & Deductions.

5.2 Service Affiliates

Hydro Ottawa provides services to its' affiliates Hydro Ottawa Holding Inc. and Energy Ottawa Inc. under the terms of Service Level Agreements, which are updated annually.

Hydro Ottawa provides Human Resources, Facilities, IT, Finance and Communications services to Hydro Ottawa Holding Inc. Energy Ottawa Inc. receives Human Resources, Facilities, IT, Finance, Metering/Meter Data and Mechanical services from Hydro Ottawa.

Details on the services Hydro Ottawa provides and receives from Affiliate transactions are provided in Exhibit D-2-1. For convenience, a summary of the associated revenue offsets are provided in Table 2, below.

Table 2: Summary of Affiliate Services Revenue Earned by Hydro Ottawa

Services From	Services to	2012 Actual	2013 Actual	~~2014 Budget Year~~	2014 Actual	2015 Bridge Year	2016 Test Year
Hydro Ottawa Ltd.	Hydro Ottawa Holding Inc.	$743,921	$771,477	~~$785,029~~	$779,165	$818,932	$835,388
Hydro Ottawa Ltd.	Energy Ottawa Inc.	$532,668	$983,140	~~$989,715~~	$976,273	$1,043,155	$1,061,482
Total		**$1,276,589**	**$1,754,617**	**~~$1,774,744~~**	**$1,755,438**	**$1,862,087**	**$1,896,870**

5.3 Services to Third Parties

These revenues, net of expenses, relate to services provided to customers or third parties such as installing and removing temporary services, isolating and re-energizing of services, transformer vault shutdown escort services, inspection services, generator services and a recently introduced bill reporting service. A small amount of revenue is also forecasted for providing ad hoc web portal services for viewing interval meter data in a web-based format.

Hydro Ottawa rents out its underground civil capacity to third parties, on a temporary basis, through a five-year Access Agreement ("duct rentals"). Duct rental agreements exist with the City of Ottawa and Rogers Cable. Hydro Ottawa has several third party pole attachments which pay an annual charge, per attachment (part of Specific Service Charges). These third parties include street light owners, telecoms and Hydro One. Pole attachment charges are proposed to increase, as part of this Application, as outlined in Exhibit H-7-1, Section 3.3 and calculated in Attachment H-7(A).

Water heater billing services are forecast to expire on December 31, 2015.

As noted in Section 4.0, generator service revenues will be recorded under Other Operating Revenue, as of 2016.

5.4 Property Rental

Property rental relates to fees paid by Hydro One Networks Inc. ("Hydro One") for land owned by Hydro Ottawa. In many locations in the City of Ottawa, Hydro Ottawa and Hydro One have joint facilities for transformer stations. For locations in which Hydro Ottawa owns the land on which Hydro One has facilities, a rental fee is paid. An additional source of income is from rent paid by the tenants of a small number of houses Hydro Ottawa purchased next to distribution stations many years ago to facilitate future station expansion.

5.5 Gains and Losses on Disposal of Property

Hydro Ottawa periodically disposes of assets that are no longer, necessary in serving the public (e.g. fully amortized vehicle, equipment, et cetera). Where the proceeds vary from the net book value of an asset, Hydro Ottawa treats the variances as a debit or credit to income.

Prior to 2014, the associated gains and losses were applied to USofA 4355 and 4360, respectively. As of 2014 forward, the net amount has been applied to USofA 4362.

5.6 Revenues from Non-Utility Operations

Non-utility income is not considered a "revenue offset" in that it does not reduce the distribution (base) revenue requirement. Hydro Ottawa has very little non-utility income with the exception of Conservation and Demand Management ("CDM") activities.

Between 2012 and 2014, Hydro Ottawa recorded a modest amount of revenue from the Ontario Power Authority micro-FIT program, from operating solar panels at two Hydro Ottawa properties, under USofA 4375. As of 2015, related revenues are not recorded under Other Revenue

5.7 Interest and Dividend Income

Interest income refers to interest earned on cash balances within the year. In the years 2012 to 2014 a modest amount of interest was recorded. Material cash balances are not anticipated between years 2015 and 2020.

6.0 OTHER REVENUE – VARIANCE ANALYSIS

Material financial and trending variance explanations are provided in the following year-to-year comparisons.

2012 Actual to 2013 Actual

2013 Other Revenue actuals of $8,980k were 12.9 percent higher than 2012 actuals.

Miscellaneous Service Revenues (4235) increased $1,709k, or, 47 percent in 2013 primarily due to the write-off of old outstanding account credit balances, in preparation for Hydro Ottawa's customer information system conversion to CC&B in 2014. Processes are now in place to monitor account credit balances in excess of one year, on a quarterly basis and clear such balances as appropriate.

Revenues from Merchandising and Jobbing (4325 Work for Others) were $4,652k, or, 97 percent higher primarily due to $946k associated with the commencement of the City of Ottawa Light Rail Transit ("LRT") project, which included abnormally high temporary power supply work and $1,556k resulting from a non-routine land trunk extension and major voltage conversion. $1,517k was the result of the recovery of damaged assets which were mistakenly applied to this revenue category, rather than Gain and Loss on Disposal of Property (4355 and 4360). Had this error not occurred, the 2013 Merchandising and Jobbing revenues (4325) would have been $7,897k.

Costs from Merchandising and Jobbing (4330 Work for Others) were 79 percent higher, primarily due to the City of Ottawa LRT project at $898k; the non-routine land trunk extension at $1,285k and the voltage conversion at $233k. An overall increase in construction and customer demand activity accounts for the balance of $656k.

In light of the aforementioned accounting treatment, Gain and Loss on disposal of Property (4355 and 4360)) is adjusted by $1,517k. Therefore, the actual Gain and Loss on disposal of Property for 2013 is $1,040k.

2013 Actual to 2014 ~~Forecast~~Actual

~~Overall,~~ The 2014 ~~Forecast~~actual Other Revenues ~~is expected to~~were $452k above the 2013 actuals ~~at~~of $8,984k, at $9,436k.

Miscellaneous Service Revenues (4235) ~~are expected to be~~ were $~~1,491k~~$1,021 lower than 2013 actuals, which were abnormally high due to non-routine credit balance write-off activity. The 2014 actuals also include $460k of credit balance write-offs.

Revenues from Merchandising and Jobbing (4325) ~~are anticipated to be $4,008~~ were $4,116k lower than 2013 actuals due to the anticipated return of more standard work program activities, including the LRT project.

For similar reasons, 2014 actual costs from Merchandising and Jobbing (4330) ~~are expected to be $2,875~~ were $3,300k lower than 2013 actuals.

As of 2014, Gain and Loss on Disposal of Property (4355 and 4360) were consolidated under USofA 4362. A ~~modest~~ loss of ~~$54k~~ $306k was realized ~~is forecast for~~ in 2014.

2014 ~~Forecast~~Actual to 2015 Bridge Year

Other Revenue in 2015 is forecasted to trend lower than ~~closely to~~ 2014 ~~forecast~~ actual levels at $8,847k. Slight declines in Retail Service, Late Payment and Miscellaneous Service revenues are expected to be offset by modest increases in revenues associated with services to third parties and asset disposals. There are no miscellaneous revenues anticipated in 2015, which primarily accounts for the overall $452k forecasted reduction.

2015 Bridge Year to 2016 Test Year

Other Revenue in 2015 is forecasted at $11,700k. The increase of $2,852k, or, 32 percent over 2015, is primarily due to proposed increases in Retail, Generation and Specific Service charges. Details on the proposed service charge changes are outlined in Exhibits H-7-1 and H-7-2. A summary of the Service Charge revenues between 2012 through 2020 is provided in Exhibit C-2-2.

2016 Test Year to 2017 Test Year

Other Revenue in 2016 is forecasted to trend closely to 2015 forecast levels, at $11,565k. A decline in Late Payment Charge revenue is forecasted in 2016, due to the

active promotion of automated payment withdrawal services to major accounts, which have a large number of accounts. Initial trends indicate that this option is gaining momentum in the major accounts sector. For this reason, Late Payment Charge revenue is expected to decline from $75k per month to $60k per month in 2017.

The forecasted decline in Late Payment Charge revenue is partially offset by a 2.1 percent inflationary increase to new and revised service charges.

2017 Test Year to 2018 Test Year

Other Revenue is forecast to increase modestly in 2018 at $11,722k. A 2.1 percent inflationary increase applied to new and revised service charges is expected to be partially offset by negligible forecasted interest earnings, as no material cash balances are expected during this period.

2018 Test Year to 2019 Test Year

Other Revenue is forecast to increase modestly in 2019 at $11,802k. A 2.1 percent inflationary increase applied to new and revised service charges is expected to be partially offset by negligible forecasted interest earnings, as no material cash balances are expected during this period.

2019 Test Year to 2020 Test Year

Other Revenue is forecast to increase modestly in 2020 at $11,898k. A 2.1 percent inflationary increase applied to new and revised service charges is expected to be partially offset by negligible forecasted interest earnings, as no material cash balances are expected during this period.

File Number:	EB-2015-004
Exhibit:	C
Tab:	2
Schedule:	1
Page:	1 of 1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2014

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2012 Actual	2013 Actual	~~2014 Forecast~~	2014 Actuals	Bridge Year² 2015	Bridge Year² 2015	Test Year 2016
	Reporting Basis	**MIFRS**	**MIFRS**	~~MIFRS~~	MIFRS		**MIFRS**	**MIFRS**
4235	**Specific Service Charges**	$ 3,583,148	$ 5,292,621	~~$ 3,801,357~~	$ 4,272,367	N/A	$ 3,710,267	$ 5,910,525
4225	**Late Payment Charges**	$ 872,023	$ 906,905	~~$ 956,249~~	$ 846,015	N/A	$ 898,752	$ 898,752
4082	Retail Services Revenues	$ 208,790	$ 100,517	~~$ 213,645~~	$ 102,313	N/A	$ 159,204	$ 171,228
4084	Service Transaction Requests	$ 7,502	$ 5,816	~~$ 7,613~~	$ 5,065	N/A	$ 5,616	$ 6,132
4086	SSS Admin Charge	$ 980,504	$ 897,531	~~$ 842,277~~	$ 921,890	N/A	$ 760,485	$ 891,797
4090	Electric Services Incidental to Energy Sales	$ -	$ -	~~$ -~~	$ 37,387	N/A	$ -	$ 341,400
4315	Revenues from Leased Plant	$ 1,737,805	$ 1,768,330	~~$ 1,822,147~~	$ 1,820,686	N/A	$ 1,823,686	$ 1,839,502
4325	Revenues from Merch, Jobbing	$ 4,762,170	$ 9,414,470	~~$ 5,406,047~~	$ 5,298,615	N/A	$ 5,486,488	$ 5,459,437
4330	Expenses from Merch, Jobbing	-$ 3,866,634	-$ 6,938,273	~~-$ 4,062,449~~	$ 3,638,594	N/A	-$ 4,186,206	-$ 4,045,020
4355	Gain on Disposal of Property	-$ 468,071	-$ 2,557,273	~~$ -~~		N/A	$ -	$ -
4360	Loss on Disposal of Property	-$ 3,687	$ -	~~$ -~~		N/A	$ -	$ -
4362	Loss from Retirement of Utility and Other Property	$ -	$ -	~~-$ 54,605~~	$ 306,457	N/A	$ 189,121	$ 198,349
4375	Revenues from Non-Utility Operations	$ 2,712	$ 2,513	~~$ 38,450~~	$ 53,031	N/A	$ -	$ -
4405	Interest and Dividend Income	$ 139,142	$ 86,990	~~$ 13,073~~	$ 23,952	N/A	$ -	$ 27,436
Specific Service Charges		$ 3,583,148	$ 5,292,621	~~$ 3,801,357~~	$ 4,272,367	N/A	$ 3,710,267	$ 5,910,525
Late Payment Charges		$ 872,023	$ 906,905	~~$ 956,249~~	$ 846,015	N/A	$ 898,752	$ 898,752
Other Operating Revenues		$ 1,196,796	$ 1,003,864	~~$ 1,063,535~~	$ 1,066,655	N/A	$ 925,305	$ 1,410,557
Other Income or Deductions		$ 2,303,437	$ 1,776,757	~~$ 3,162,663~~	$ 3,251,233	N/A	$ 3,313,089	$ 3,479,704
Total		$ 7,955,404	$ 8,980,147	~~$ 8,983,804~~	$ 9,436,270	N/A	$ 8,847,413	$ 11,699,538

Description	**Account(s)**
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4405 - Interest and Dividend Income

	2012 Actual	2013 Actual	2014 Forecast	2014 Actual	Bridge Year² 2015	Bridge Year² 2015	Test Year 2016
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**		**MIFRS**	**MIFRS**
Short-term Investment Interest							
Bank Deposit Interest	$ 139,142	$ 86,990	$ 13,073	$ 23,952		$ -	$ 27,436
Miscellaneous Interest Revenue							
etc.[1]							
Total	$ 139,142	$ 86,990	$ 13,073		$ -	$ -	$ 27,436

Notes:

1 List and specify any other interest revenue.

2 In the transition year to IFRS, the applicant is to present information in both MIFRS and CGAAP. For the typical applicant that is adopting IFRS on January 1, 2015, 2014 must be presented in both a CGAAP and MIFRS basis.

SERVICE CHARGE REVENUE

1.0 INTRODUCTION

As noted in Exhibit H-7-1, Hydro Ottawa Limited ("Hydro Ottawa") reviewed and revised a number of service charges as part of this application. This review included Specific Service, Generator Service and Retailer Service Charges ("Service Charges"). A complete listing of existing and proposed service charges from 2012 through 2020 is provided in Table 1, of Exhibit H-7-1.

In terms of Other Revenue impacts, the proposed Service Charges are forecasted to increase 2016 Service Charge revenues by 65.5 percent, or $2,520k, as compared to 2015 forecasted Service Charge revenues. The majority of this revenue increase is driven by proposed increases in Service Charges, as compared to volumetric increases.

Between the years of 2013 to 2015, Temporary Service revenues were recorded under Merchandising and Jobbing (4325 Work for Others). Similarly, Generation Service revenues were recorded under (4325 Work for Others) during the years 2012 to 2015. As of 2016, the associated revenues shall be recorded under Miscellaneous Revenue (4235) and Other Operating Revenue (4090), respectively. For comparison, these amounts are shown under Service Charges, but, not included in the respective 2012 to 2015 Service Charge revenue totals.

A summary of the Service Charges and applicable revenues for the years 2012 through 2020 is provided in the following Table 1:

Table 1 – Summary of Service Charge Revenue 2012 to 2020

SPECIFIC SERVICE CHARGE REVENUE	2012 Actual Revenue	2013 Actual Revenue	~~2014 Forecast Revenue~~	2014 Actual Revenue	2015 Forecast Revenue	2016 Forecast Revenue	2017 Forecast Revenue	2018 Forecast Revenue	2019 Forecast Revenue	2020 Forecast Revenue
Enrollment Request Fee	$100	$100	-	$300						
Account Certificate (i.e., easements, arrears)	$8,096	$4,454	~~$3,754~~	$4,284	$4,308	$4,308	$4,308	$4,308	$4,308	$4,308
Duplicate invoices for previous billing	$2,550	$1,905	~~$2,667~~	$2,640	$2,544	$2,544	$2,544	$2,544	$2,544	$2,544
Credit reference/credit check (plus credit agency costs)	$1,395	$840	~~$621~~	$390	$816	$816	$816	$816	$816	$816
Unprocessed Payment Charge (plus bank charges)	$28,725	$29,190	~~$34,164~~	$45,540	$28,008	$28,008	$28,008	$28,008	$28,008	$28,008
Account set up charge/change of occupancy charge	$1,889,773	$1,928,323	~~$2,045,859~~	$1,953,117	$1,972,595	$1,992,321	$2,012,253	$2,032,376	$2,052,700	$2,073,227
Collection of account charge - no disconnection	$18,150	$24,870	~~$25,476~~	$29,820	$24,792	$24,792	$24,792	$24,792	$24,792	$24,792
Disconnect/Reconnect at meter - regular hours	$118,675	$208,200	~~$185,916~~	$244,997	$189,288	$189,288	$189,288	$189,288	$189,288	$189,288
Disconnect/Reconnect at meter - after regular hours	$71,225	$162,430	~~$146,468~~	$172,050	$138,276	$138,276	$138,276	$138,276	$138,276	$138,276
Disconnect/Reconnect at pole - regular hours			-	$1,660		$0	$0	$0	$0	$0
Disconnect/Reconnect at pole - after regular hours	$1,245	$415	-			$0	$0	$0	$0	$0
Other Billing Info Request (proposed Special Billing Service)	$4,485	$4,335	~~$4,224~~	$3,975	$4,608					
Special Billing Service (formerly Other Billing Info Request) per hr			-			$4,750	$4,850	$5,000	$5,100	$5,200
Temporary service install & remove - overhead - no transformer	$11,498	$51,000	~~$36,000~~		$45,000	$55,790	$56,910	$58,100	$59,360	$60,620
Temporary service install & remove - underground - no transformer			-			$11,560	$11,800	$12,050	$12,300	$12,560
Temporary service install & remove - overhead - with transformer			-			$71,000	$72,500	$74,025	$75,575	$77,175
Specific Charge for Access to the Power Poles (per pole attachment)	$1,410,545	$1,321,742	~~$1,335,042~~	$1,336,376	$1,328,028	$3,211,779	$3,211,779	$3,268,126	$3,268,126	$3,268,126
Dry Core Transformer Charge - Demand (per attached Table)	$16,664	$16,923	~~$17,167~~	$17,362	$17,004	$19,476	$20,255	$21,390	$22,480	$23,245
Reconnect at meter - regular hours (under account administration section - new account)			-			$149,500	$149,500	$149,500	$149,500	$149,500
Reconnect at meter - after regular hours (under account administration section - new account)			-			$2,220	$2,220	$2,220	$2,220	$2,220
Interval Meter - Field Reading			-			$0	$0	$0	$0	$0
High Bill Investigation - If billing is correct			-			$0	$0	$0	$0	$0
Service Call - Customer missed appointment - (Reg. Hours)			-			$1,625	$1,625	$1,625	$1,625	$1,625
Service Call - Customer missed appointment (After Reg. Hours)			-			$925	$925	$925	$925	$925
Energy Resource Facility Administration Charge - Without Account Set Up (one-time)			-			$762	$780	$798	$810	$828
Energy Resource Facility Administration Charge - With Account Set Up (one-time)			-			$785	$800	$815	$825	$840

SPECIFIC SERVICE CHARGE REVENUE	2012 Actual Revenue	2013 Actual Revenue	~~2014 Forecast Revenue~~	2014 Actual Revenue	2015 Forecast Revenue	2016 Forecast Revenue	2017 Forecast Revenue	2018 Forecast Revenue	2019 Forecast Revenue	2020 Forecast Revenue
Misc Revenue	$22	$1,588,894	-	$459,856						
Total Service Charge Revenue	**$3,583,148**	**$5,292,621**	~~$3,801,358~~	**$4,272,367**	**$3,710,267**	**$5,910,525**	**$5,934,229**	**$6,014,982**	**$6,039,578**	**$6,064,123**
RETAILER SERVICE REVENUE			-							
Standard Charge			-			$0	$0	$0	$0	$0
Monthly Fixed Charge, per Retailer			-			$5,184	$5,400	$5,616	$5,832	$6,048
Monthly Variable Charge, per Customer, per Retailer			-			$105,397	$103,102	$109,262	$106,883	$112,598
Monthly Billing Charge ("DCB"), per Customer, per Retailer			-			$60,653	$59,230	$66,103	$64,552	$63,037
Service Transaction Requests ("STR") Fee, per request			-			$2,891	$2,840	$2,790	$3,198	$3,141
Service Transaction Requests ("STR") Fee, per process			-			$3,239	$3,072	$3,156	$2,994	$3,058
Total Retailer Service Revenue	**$216,292**	**$106,333**	~~$221,258~~	**$107,378**	**$164,820**	**$177,364**	**$173,644**	**$186,927**	**$183,458**	**$187,882**
GENERATOR SERVICE REVENUE			-							
Micro-FIT and Micro-Net-Metering Energy Resource Facility Monthly Account Management Charge (formerly MicroFIT monthly account management charge)	$6,777	$26,676	~~$28,253~~	$37,387	$34,473	$152,064	$157,248	$171,456	$176,928	$182,400
FIT Monthly Account Management Charge			-			$161,364	$164,076	$168,144	$170,856	$174,924
HCI, RESOP, Other Energy Resource Facility Monthly Account Management Charge			-			$27,972	$28,512	$29,160	$35,604	$48,613
Total Generator Service Charges	**$6,777**	**$26,676**	~~$28,253~~	**$37,387**	**$34,473**	**$341,400**	**$349,836**	**$368,760**	**$383,388**	**$405,937**
Total 2016 Service Charges Updates - Forecasted Revenue	**$3,806,217**	**$5,425,630**	~~$4,050,869~~	**$4,417,132**	**$3,909,560**	**$6,429,289**	**$6,457,709**	**$6,570,669**	**$6,606,424**	**$6,657,942**

1

OPERATING EXPENSES - SUMMARY

This Exhibit provides an overview of Hydro Ottawa's total operating costs. These costs include Operations, Maintenance and Administration ("OM&A") including property taxes, Depreciation and Amortization expenses; and Payments in Lieu of Taxes ("PILS"). Detailed information with respect to each of these operating costs is available in Exhibits D-1-2 and D-1-3, D-3-1 and D-4-1.

1.0 Summary of Operating Expenses 2012-2016

Table 1

($000s)	2012 Actual	2013 Actual	~~2014 Q2 Forecast~~	2014 Actual	2015 Bridge	2016 Test Year
OM&A (including Property Tax)	$73,076	$75,757	~~$80,767~~	$80,909	$83,656	$87,106
Depreciation/ Amortization	$38,595	$39,798	~~$36,517~~	$35,923	$38,558	$40,826
PILS (income taxes)	$6,857	$6,806	~~$3,000~~	$908	NIL	$4,958
Total Operating Costs	$118,528	$122,361	~~$120,284~~	$117,740	$122214	$132,890

2.0 OM&A

Hydro Ottawa's OM&A expenses for the 2016 test year are forecasted to be $ 87.1. This represents a compound annual growth rate of 5.5% over the 2012-2016 timeframe.

The principle cost drivers underlying Hydro Ottawa's forecasted OM&A expenses include costs associated with compliance with legislative and regulatory compliance, compensation and labour costs, inflation and certain operational and maintenance costs that Hydro Ottawa must incur to continue to provide a safe and reliability electricity distribution system.

2.1 Inflation Rates and Financial Assumptions

Hydro Ottawa has assumed an inflation rate of 2.13% for 2015 and 2.01% for 2016 for all non-compensation related costs. For the 2017-2020 rate period, an escalation factor of 3.245% is applied to OM&A expenditures which is the result of the I-X formula.

Labour costs are adjusted to reflect market conditions for non-unionized employees and to align with the collective agreement annual rate adjustment for unionized employees.

2.2 Compensation Costs

Labour costs are adjusted to reflect market conditions for non-unionized employees and to align with the collective agreement annual rate adjustment for unionized employees. Hydro Ottawa's forecasted total compensation costs for the 2016 test year are $71,944K. This represents a compound annual growth rate of 4.3% over the 2012 to 2016 timeframe. For more information regarding Hydro Ottawa's compensation costs please refer to Exhibit D-1-8.

3.0 Depreciation and Amortization expenses

Hydro Ottawa adheres to the Modified International Financial Reporting Standards ("MIFRS") as its accounting standard which informs its rate making and regulatory reporting requirements. Hydro Ottawa uses the half-year rule for calculating depreciation/amortization in the year that capital additions are added into rate base. For more information regarding Hydro Ottawa's Depreciation/Amortization expense, please refer to Exhibit D-3-1.

4.0 Payments in Lieu of Taxes ("PILS") and Property Taxes.

Pursuant to its obligations under Section 93 of the Electricity Act 1998 (Ontario), as amended, Hydro Ottawa is liable for the payment of PILS to the City of Ottawa based on its taxable income. Hydro Ottawa expects to pay $0 in PILS in 2015 and $ $4,958K in

PILS in 2016. For more information regarding PILS, please refer to Exhibit D-4-1 1 for further details.

OM&A OVERVIEW

This schedule provides a brief qualitative and quantitative summary of Hydro Ottawa Limited's ("Hydro Ottawa" or "the Company") Operations, Maintenance and Administration ("OM&A") expenditures including a brief overview of the composition of Hydro Ottawa's OM&A costs, the significant OM&A cost drivers and year over year variances, trends and business environment changes. This schedule further describes Hydro Ottawa's approach to OM&A planning and the top down and bottom up budget process used to arrive at Hydro Ottawa's OM&A expenditures. The information contained in this schedule is informed by the OEB's filing requirements set out on page 33 in Chapter 2 of the Ontario Energy Board's (OEB's) Filing requirements for Electricity Distribution Rate Applications, as updated on July 18, 2014.

1.0 OM&A SUMMARY

1.1 Hydro Ottawa's Approach to OM&A Planning and Budgeting

Hydro Ottawa's approach to OM&A planning and budgeting for the 2016-2020 period is guided by Hydro Ottawa's planning and performance management framework which aligns the Company's corporate strategies with planning, operations, performance and the drive for continuous improvement.

The framework maintains that spending correspond to business priorities, be directed to achieve performance targets and support Hydro Ottawa's four key focus areas as set out in its *2012-2016 Strategic Direction*. The four key focus areas for the Company are:

- Customer value;
- Financial strength;
- Organizational effectiveness; and
- Corporate citizenship.

Hydro Ottawa's 2016 OM&A budget was developed as a test year rebasing budget but was guided by the constraints enunciated in the February 2014 budget memo from Hydro Ottawa's Chief Financial Officer (Attachment D-1(A)) which, among other things, included constraints on headcount and compensation and OM&A. Hydro Ottawa's 2016 OM&A budget was further informed by substantive operational investments needed to maintain service reliability and safety as well as those necessary to remain in compliance with regulatory and legislative requirements. Finally, Hydro Ottawa's OM&A budget was informed by the need to maximize productivity and minimize bill impacts while ensuring the financial health and viability of the Company.

For the 2017-2020 test years, Hydro Ottawa will adjust OM&A using an I-X formula to align with the principles of incentive regulation as enunciated in the Renewed Regulatory Framework for Electricity (RRFE). Hydro Ottawa seeks approval for final rates for a three year period beginning 2016 and ending 2018. In 2017 Hydro Ottawa proposes to apply for revised rates that will be adjusted to incorporate a revised inflation factor and updated cost of capital parameters. Hydro Ottawa's approach to adjusting the OM&A component of rates by a I-X formula, results in the Company bearing the risk associated with any shortfall between revenues collected through rates and regularly incurred costs. This difference must be recovered through productivity initiatives and operational efficiencies. Hydro Ottawa further assumes the risk associated with not adjusting rates for the first three years to reflect changes to inflation or cost of capital.

1.2 OM&A Budget Process

Hydro Ottawa undertook both a top down and bottom up forecasting exercise to develop the 2016 test year budget. The 2016 budget forecast exercise began with the development of the Budget Memo from the office of the Chief Financial Officer that provided top down guidance on the areas of constraints which informed the individual divisions in the development of their bottom up budgets. Examples of top down constraints include constraints on hiring and on compensation, benefits, productivity, and cost control. Bottom up funding requests were then developed and evaluated and scrutinized based on priority and alignment with core company strategic directives as

well as ratepayer impacts. Adjustments were subsequently made to the 2016 OM&A budget to reflect corporate priorities and customer rate impacts. The final 2016 OM&A budget was developed to accommodate Hydro Ottawa's operational requirement to provide a safe and reliable distribution system while respecting legislative and regulatory obligations and the conditions of its license.

As noted above, the OM&A budget for the 2017-2020 test years was subsequently calculated based on an I-X formula typical of incentive regulation models. Although the budget was assessed for rate impacts no further adjustments were made. Recognizing that Hydro Ottawa cannot accurately predict all potential OM&A funding requirements that may emerge during the 2017-2020 custom IR term, it may avail itself to the cost recovery mechanism available under a Z factor application. Hydro Ottawa will only resort to using the Z factor mechanism if costs incurred arise from unforeseen events, decisions or activities, the results of which cannot be reasonably anticipated or quantified at this juncture and where the costs exceed Hydro Ottawa's materiality threshold. . Examples include unforeseen weather events or changes to laws or regulations requiring significant implementation investment.

For more details on Hydro Ottawa's Custom IR model, see Exhibit A-2-1.

1.3 OM&A Composition

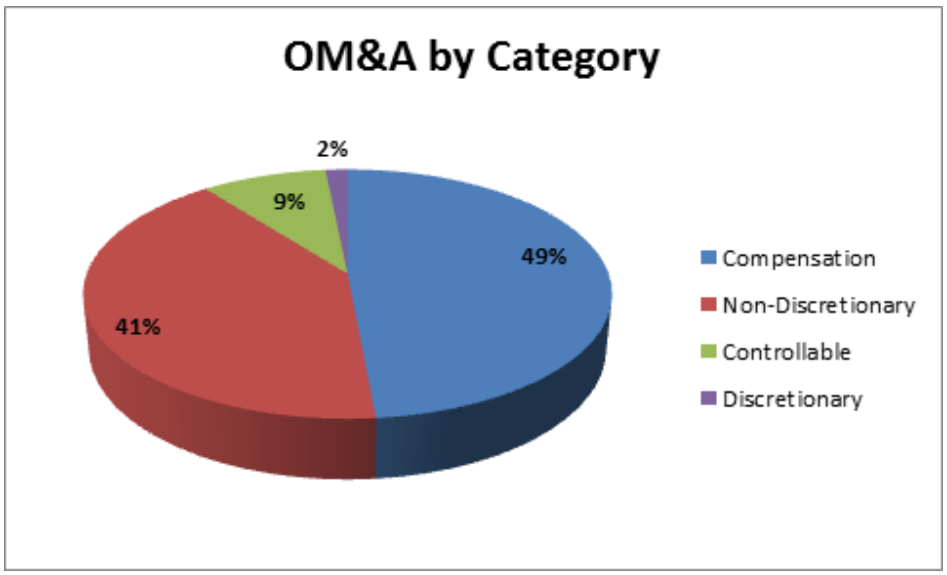
In support of the Company's cost control initiative, an OM&A review was conducted during the 2014 budget process. The review capture all the costs of the main business activities broken down into four distinct categories:

1) Compensation: Headcount costs including payroll and benefits;
2) Non-Discretionary OM&A: Statutory requirement costs that are fixed or dictated by external factors and/or minimum contracts. Examples include the OEB fees, property tax, audit fees, and insurance premium, and underground locates;
3) Controllable OM&A: Costs that must be incurred. Volumes and/or service levels are controlled by management and can be adjusted in the short term. Examples include bank charges, fuel, utilities, manhole cleaning; and

4) Costs that can be reallocated or eliminated without significant impact to current operations or customer relations. Examples include non-safety training, non-essential consulting, travel, and meals, community services.

As Figure 1 below denotes compensation costs represent 49% of Hydro Ottawa's OM&A costs while 41% are non-discretionary costs, 9% are controllable and only 2% are discretionary.

Figure 1 – OM&A by Category



Source: Hydro Ottawa 2014 Analysis

1.4 OM&A Test Year Levels

The proposed OM&A costs for the test years range from $87.1 million in the 2016 test year to $99.0 million in the 2020 test year.

2017 – 2020 test year OM&A costs are adjusted by Hydro Ottawa's Custom IR model which is based on the Conference Board of Canada's forecasted GDP IPI minus a negative productivity factor of -1.145% to provide an annual I-Xadjustment of 3.245%. The projected OM&A expenditures are necessary to maintain reasonable business

continuity while managing the risks associated with the many labour, legislative and regulatory transformations taking place in the electricity industry.

1.5 Summary of Total OM&A Expenditures

Hydro Ottawa's OM&A costs are significantly influenced by its requirement to operate and maintain a safe and reliable distribution grid, provide service levels that are satisfactory to customers while ensuring its continued compliance with all legislative and regulatory obligations. Among other things, this entails that it strategically manages its workforce in a manner that allows it to replace retiring workers with new tradespeople and respond to the changing dynamics of the market and operating environment within which it is tasked with distributing electricity to customers.

Table 1 below provides a summary view of Hydro Ottawa's historical, bridge, test and forecast year OM&A expenditures.

Table 1 – OM&A Variances (in thousands of dollars) and (%) by Year

Year	OM&A	Previous Year	Variance ($)	Variance (%)
2012 Actual	$73,076			
2013 Actual	$75,757	$73,076	$2,681	3.7%
~~**2014 Q2 Forecast**~~	~~$80,767~~	~~$75,757~~	~~$5,010~~	~~6.6%~~
2014 Actual	$80,909	$75,757	$5,152	6.8%
~~**2015 Bridge Year**~~	~~$83,656~~	~~$80,767~~	~~$2,889~~	~~3.6%~~
2015 Bridge Year	$83,656	80,909	$2,747	3.4%
2016 Test Year	$87,106	$83,656	$3,450	4.1%
2017 Forecast	$89,932	$87,106	$2,826	3.2%
2018 Forecast	$92,850	$89,932	$2,918	3.2%
2019 Forecast	$95,863	$92,850	$3,013	3.2%
2020 Forecast	$98,974	$95,863	$3,111	3.2%

1.6 Summary of OM&A Costs by Major Category

Appendix 2-JA provides a summary of the recoverable OM&A Expenses as summarized below in Table 2. See also Exhibit D-1-2 for a description of high level cost drivers and cost drivers by program.

Table 2 – OM&A costs by major OM&A Category (in thousands of dollars)

OM&A Category	2012 Actuals	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	CAGR
Operations	$14,994	$15,607	~~$17,497~~	$16,337	$18,467	$20,491	8.1%
Maintenance	$9,884	$9,612	~~$9,634~~	$10,973	$11,073	$10,386	1.2%
Subtotal	***$24,878***	***$25,219***	~~***$27,131***~~	***$27,309***	***$29,540***	***$30,877***	***5.5%***
Billing and Collecting	$9,590	$10,135	~~$12,057~~	$12,009	$12,397	$12,556	7.0%
Community Relations	$5,550	$5,352	~~$5,705~~	$5,340	$5,960	$6,162	2.6%
Subtotal	*$15,140*	*$15,487*	~~*$17,762*~~	*$17,349*	*$18,357*	*$18,718*	*5.4%*
Administrative and General	$33,058	$35,051	~~$35,874~~	$36,251	$35,759	$37,511	3.2%
Total OM&A Expenses	***$73,076***	***$75,757***	~~***$80,767***~~	***$80,909***	***$83,656***	***$87,106***	***4.5%***

a) Operations and Maintenance Costs

Operations and Maintenance costs increased by a compound annual growth rate of 5.5% (2012 to 2016). The increase to operations and maintenance related costs is partly attributable to increased costs associated with labour and maintenance expenses associated with operating and maintaining overhead and underground distribution lines, feeders, transformers and distribution stations. Hydro Ottawa's operations and maintenance costs were further influenced by new programs designed to invest in proactive operational and maintenance measures to avoid long term OM&A and capital costs. Examples of such programs include vegetation management and asset maintenance to name a few. The principle cost drivers of the increases are:

- Compensation costs;

- Increased regulatory and legislative obligations compelling compliance. Examples include Bill 168 (Occupational Health & Safety, Bill 8 Underground Locates; various OEB codes changes, Green Energy Act, Smart Meters and meter data costs; and
- New technology costs such as SCADA, GIS and Asset Management software.

b) Billing and Collections & Community Relations

Billing and Collections and Community Relations costs increased by compound annual growth rate of 5.4% (2012 to 2016). Billing and collections expenses relate to costs associated with transitioning to monthly billing, enabling customer billing services and conducting collections activities. The principle cost drivers of the increases are:

- Compensation costs;
- Increase to technology costs to enable meter data post-AMI (Automated metering Infrastructure) deployment as well as technology costs to support the customer care and billing system; and
- Increase to postage costs to support monthly billing.

c) Administrative and General

Administrative and General costs increased by an compound annual growth rate of 3.2% (2012 to 2016). Administrative costs generally reflect salary expenses as well as costs associated with HR, IT, Finance, Regulatory, and others. The principle cost drivers of the increases are:

- Compensation and benefits costs.

1.7 Inflation Rates and Financial Assumptions

Hydro Ottawa has assumed an inflation rate of 2.13% for 2015 and 2.01% for 2016 for all non-compensation related costs. For the 2017-2020 rate period, an escalation factor of 3.245% is applied to OM&A expenditures which is the result of the I-X formula.

1.8 Business Environment Changes

Business environment changes that have occurred and that are expected to continue to occur in Hydro Ottawa's territory are changes arising from the proliferation of distributed generation and new technologies emerging within its serving territory all of which is impacting to Hydro Ottawa's current and prospective revenues. On the horizon, Hydro Ottawa anticipates further changes to be triggered by further implementation of the Ministry of Energy's Long Term Energy Plan as well as new initiatives introduced by the Independent Electricity System Operator (IESO) such as changes to the MDM/R. Individually and collectively these changes will have an impact on the way in which Hydro Ottawa manages its business and the operational costs it must absorb.

1.9 Overview of OM&A Programs & Expenditures

A full quantitative description and variance of Hydro Ottawa's full program costs is available in Appendix 2-JC and a qualitative description of Hydro Ottawa's OM&A programs and an analysis of cost drivers can be found in Exhibit D-1-3.

2.0 OM&A COST PER CUSTOMER AND PER FTE

Table 3 summarizes Hydro Ottawa's historical, bridge and test year year over year OM&A expenditures expressed on a per customer and per Full Time Equivalent Employees ("FTE") basis. Table 3 illustrates relatively flat increases in the number of customers as well as a decreasing then flat FTE trend.

Table 3 - OM&A Cost per Customer and FTE

	Last Rebasing Year – 2012 – Board Approved	Last Rebasing – 2012 – Actual	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis							
Number of Customers		309,534.00	314,722.00	~~313,501.00~~	319,593.00	323,197.00	327,260.00
Total Recoverable OM&A from Appendix 2-JB	$73,090,393	$73,076,334	$75,757,157	~~$80,767,417~~	$80,908,994	$83,655,809	$87,105,564
OM&A cost per customer		$236.08	$240.71	~~$257.63~~	$253.16	$258.84	$266.17
Number of FTEs		593.5	610.6	~~627.8~~	622	622.7	622.7
Customers/FTEs		521.54	515.43	~~499.36~~	513.82	519.03	525.55
OM&A Cost per FTE		$123,127.77	$124,070.02	~~$128,651.51~~	$130,078.77	$134,343.68	$139,883.67

File Number:	EB-2015-0004
Exhibit:	D
Tab:	1
Schedule:	2
Page:	1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	2017	2018	2019	2020
Reporting Basis	MIFRS	MIFRS	MIFRS	~~MIFRS~~	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations		$ 14,993,742	$ 15,607,433	~~$ 17,497,244~~	$ 16,336,592	$ 18,466,503	$ 20,490,724				
Maintenance		$ 9,883,523	$ 9,611,544	~~$ 9,634,371~~	$ 10,972,727	$ 11,073,276	$ 10,386,427				
SubTotal	**$ -**	**$ 24,877,265**	**$ 25,218,976**	**~~$ 27,131,615~~**	**$ 27,309,320**	**$ 29,539,779**	**$ 30,877,151**				
%Change (year over year)			1.4%	~~7.6%~~	8.3%	8.2%	4.5%				
%Change (Test Year vs Last Rebasing Year - Actual)							24.1%				
Billing and Collecting		$ 9,590,081	$ 10,135,276	~~$ 12,056,732~~	$ 12,008,902	$ 12,397,275	$ 12,555,619				
Community Relations		$ 5,550,017	$ 5,351,621	~~$ 5,705,132~~	$ 5,339,557	$ 5,959,788	$ 6,162,315				
Administrative and General		$ 33,058,970	$ 35,051,283	~~$ 35,873,937~~	$ 36,251,217	$ 35,758,966	$ 37,510,478				
SubTotal	**$ -**	**$ 48,199,068**	**$ 50,538,180**	**~~$ 53,635,801~~**	**$ 53,599,675**	**$ 54,116,030**	**$ 56,228,413**	**$ -**	**$ -**	**$ -**	**$ -**
%Change (year over year)			4.9%	~~6.1%~~	6.1%	1.0%	3.9%				
%Change (Test Year vs Last Rebasing Year - Actual)							16.7%				
Total	**$ 73,090,393**	**$ 73,076,334**	**$ 75,757,156**	**~~$ 80,767,417~~**	**$ 80,908,994**	**$ 83,655,809**	**$ 87,105,563.90**	**$ 89,932,139**	**$ 92,850,437**	**$ 95,863,434**	**$ 98,974,203**
%Change (year over year)			3.7%	~~6.6%~~	6.8%	3.4%	4.1%	3.2%	3.2%	3.2%	3.2%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	2017	2018	2019	2020
Operations	$ -	$ 14,993,742	$ 15,607,433	~~$ 17,497,244~~	$ 16,336,592	$ 18,466,503	$ 20,490,724	$ -	$ -	$ -	$ -
Maintenance	$ -	$ 9,883,523	$ 9,611,544	~~$ 9,634,371~~	$ 10,972,727	$ 11,073,276	$ 10,386,427	$ -	$ -	$ -	$ -
Billing and Collecting	$ -	$ 9,590,081	$ 10,135,276	~~$ 12,056,732~~	$ 12,008,902	$ 12,397,275	$ 12,555,619	$ -	$ -	$ -	$ -
Community Relations	$ -	$ 5,550,017	$ 5,351,621	~~$ 5,705,132~~	$ 5,339,557	$ 5,959,788	$ 6,162,315	$ -	$ -	$ -	$ -
Administrative and General	$ -	$ 33,058,970	$ 35,051,283	~~$ 35,873,937~~	$ 36,251,217	$ 35,758,966	$ 37,510,478	$ -	$ -	$ -	$ -
Total	**$ 73,090,393**	**$ 73,076,334**	**$ 75,757,156**	**~~$ 80,767,417~~**	**$ 80,908,994**	**$ 83,655,809**	**$ 87,105,564**	**$ 89,932,139**	**$ 92,850,437**	**$ 95,863,434**	**$ 98,974,203**
%Change (year over year)			3.7%	~~6.6%~~	6.8%	3.4%	4.1%	3.2%	3.2%	3.2%	3.2%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	Variance 2012 BA – 2012 Actuals	2013 Actuals	Variance 2013 Actuals vs. 2012 Actuals	~~2014 Q2 Forecast~~	~~Variance 2014 Actuals vs. 2013 Actuals~~	2014 Actual	Variance 2014 Actuals vs. 2013 Actuals	2015 Bridge Year	Variance 2015 Bridge vs. 2014 Forecast	Variance 2015 Bridge vs. 2014 Actuals	2016 Test Year	Variance 2016 Test vs. 2015 Bridge
Operations	$ -	$ 14,993,742		$ 15,607,433	$ 613,690	~~$ 17,497,244~~	~~$ 1,889,812~~	$ 16,336,592	$ 729,160	$ 18,466,503	~~$ 969,258~~	$ 2,129,910	$ 20,490,724	$ 2,024,221
Maintenance	$ -	$ 9,883,523		$ 9,611,544	-$ 271,979	~~$ 9,634,371~~	~~$ 22,827~~	$ 10,972,727	$ 1,361,184	$ 11,073,276	~~$ 1,438,905~~	$ 100,549	$ 10,386,427	-$ 686,849
Billing and Collecting	$ -	$ 9,590,081		$ 10,135,276	$ 545,195	~~$ 12,056,732~~	~~$ 1,921,456~~	$ 12,008,902	$ 1,873,625	$ 12,397,275	~~$ 340,543~~	$ 388,374	$ 12,555,619	$ 158,344
Community Relations	$ -	$ 5,550,017		$ 5,351,621	-$ 198,396	~~$ 5,705,132~~	~~$ 353,511~~	$ 5,339,557	-$ 12,064	$ 5,959,788	~~$ 254,657~~	$ 620,232	$ 6,162,315	$ 202,527
Administrative and General	$ -	$ 33,058,970		$ 35,051,283	$ 1,992,313	~~$ 35,873,937~~	~~$ 822,654~~	$ 36,251,217	$ 1,199,934	$ 35,758,966	~~$ 114,971~~	-$ 492,251	$ 37,510,478	$ 1,751,512
Total OM&A Expenses	$ 73,090,393	$ 73,076,334	$ 14,059	$ 75,757,156	$ 2,680,823	~~$ 80,767,417~~	~~$ 5,010,261~~	$ 80,908,994	$ 5,151,838	$ 83,655,809	~~$ 2,888,392~~	$ 2,746,814	$ 87,105,564	$ 3,449,755
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)														
Total Recoverable OM&A Expenses	$ 73,090,393	$ 73,076,334	$ 14,059	$ 75,757,156	$ 2,680,823	~~$ 80,767,417~~	~~$ 5,010,261~~	$ 80,908,994	$ 5,151,838	$ 83,655,809	~~$ 2,888,392~~	$ 2,746,814	$ 87,105,564	$ 3,449,755
Variance from previous year				$ 2,680,823		~~$ 5,010,261~~		$ 5,151,838		$ 2,746,814			$ 3,449,755	
Percent change (year over year)				3.7%		~~6.6%~~		6.8%		3.4%			4.1%	
Percent Change: Test year vs. Most Current Actual						~~7.85%~~		7.66%						
Simple average of % variance for all years							19.2%							4.5%
Compound Annual Growth Rate for all years														4.5%
Compound Growth Rate (2014 ~~Q2 Forecast~~ Actuals vs. 2012 Actuals)							~~5.1%~~		5.2%					

File Number:	EB-2015-004
Exhibit:	D
Tab:	1
Schedule:	2
Page:	1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE

	Last Rebasing Year - 2012- Board Approved	Last Rebasing Year - 2012- Actual	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	2017	2018	2019	2020
Reporting Basis											
Number of Customers		309,534.00	314,722.00	~~313,501.00~~	319,593.00	323,197.00	327,260.00	331,279.00	335,278.00	339,222.00	343,124.00
Total Recoverable OM&A	$ 73,090,393	$ 73,076,334	$ 75,757,157	~~$ 80,767,417~~	$ 80,908,994	$ 83,655,809	$ 87,105,564	$89,953,916	$92,895,409	$95,933,089	$99,070,101
OM&A cost per customer		$236.08	$240.71	~~$257.63~~	$253.16	$258.84	$266.17	$271.54	$277.07	$282.80	$288.73
Number of FTEs		593.5	610.6	~~627.8~~	622.0	622.7	622.7	622.7	622.7	622.7	622.7
Customers/FTEs		521.54	515.43	~~499.36~~	513.82	519.03	525.55	532.00	538.43	544.76	551.03
OM&A Cost per FTE		$123,127.77	$124,070.02	~~$128,651.51~~	$130,078.77	$134,343.68	$139,883.67	$144,457.87	$149,181.64	$154,059.88	$159,097.64

Notes:

1 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

2 The method of calculating the number of customers must be identified.

3 The method of calculating the number of FTEs must be identified. See also Appendix 2-K

4 The number of customers and the number of FTEs should correspond to mid-year or average of January 1 and December 31 figures.

OM&A COST DRIVERS, PROGRAM DELIVERY COSTS & VARIANCE ANALYSIS

1.0 INTRODUCTION

This Schedule describes Hydro Ottawa's Operating Maintenance and Administrative ("OM&A") costs by major program including variances as well as a major cost driver variance summary. The schedule further provides explanations for program costs with variances greater than $750K[1] based on historical trend. The information contained in this schedule is informed by the OEB's filing requirements set out on pages 33 and 34 in Chapter 2 of the Ontario Energy Board's ("OEB") Filing requirements for Electricity Distribution Rate Applications, as updated on July 18, 2014.

2.0 OM&A COST DRIVERS

Table 1 below sets out the year over year cost drivers impacting Hydro Ottawa's OM&A and the major cost driver variances are described below.

[1] Materiality Threshold as per Exhibit A-5-1.

Table 1: Recoverable OM&A Cost Driver Table (Appendix 2-JB)

OM&A	Last Rebasing Year (2012 Actuals)	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year
Reporting Basis			-			
Opening Balance	$ 73.1	$ 73.1	~~$ 75.8~~	$ 75.8	$ 80.9	$ 83.7
Workforce Planning			~~$ 0.2~~		$ 0.6	$ 0.4
Collective Agreement/Annual progressions		$ 1.1	~~$ 1.2~~	$ 1.7	$ 2.3	$ 1.4
Vacancy and Vacancy Allowance			~~$ (1.6)~~		$ (2.1)	$ (0.1)
Benefits & Pensions		$ 0.1	~~$ 1.7~~	$ 0.6	$ 0.8	$ 1.0
Vegetation Management		$ 0.4	~~$ 0.3~~	$ 1.5	$ (0.3)	$ (0.4)
Underground Locates		$ 0.2	~~$ 0.1~~	$ 0.1	$ 0.3	$ 0.3
Changes in Capital and Allocations		$ (0.6)	~~$ 0.2~~	$ 0.4	$ (0.4)	$ (0.2)
Postage		$ (0.1)	~~$ 0.7~~	$ 0.8	$ 0.1	$ -
IT Maintenance		$ 0.5	~~$ 1.2~~	$ 1.2	$ 0.4	$ 0.5
Bad Debts		$ 0.8	~~$ (0.4)~~	$ (0.4)	$ (0.3)	$ 0.4
Inventory Scrap recovery reclass out of OMA		$ -	~~$ 0.8~~	$ 0.6		$ -
Inflation			-		$ 0.8	$ 0.8
Other Costs/(Cost reductions)	$ -	$ 0.3	~~$ 0.6~~	$ (1.4)	$ 0.6	$ (0.7)
Closing Balance	$ 73.1	$ 75.8	~~$ 80.8~~	$ 80.9	$ 83.7	$ 87.1

2.1 Labour Compensation Costs

This includes the workforce planning, collective agreement / annual progressions and vacancy allowance. Annual salary increases and new employee progressions are governed by Hydro Ottawa's collective agreement for unionized staff. Each year unionized employee salaries are adjusted based on a negotiated percentage. Hydro Ottawa's current collective agreement with the International Brotherhood of Electrical

Workers ends March 31, 2017. Adjustments for 2016 are based on the agreement. Management staff compensation is forecasted based upon comparable annual adjustments to unionized staff adjustments. Hydro Ottawa has taken several proactive measures to constrain compensation costs including adopting a flat head count by constraining workforce hiring and replacement for the 2014-2020 period.

Table 2: Summary of Salary and Wages (Appendix 2-K)

Salary and Wages ($000s)	2012 Actuals	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	CAGR
	$ 49,369	$ 52,268	~~$ 55,232~~	$53,874	$ 55,734	$ 57,759	4.0%

2.2 Benefits & Pensions

This category includes costs associated with all of Hydro Ottawa's staff benefits and pensions including current and post-retirement health benefits, employer payroll taxes and employer pension contributions. Hydro Ottawa has taken measures to constrain these costs, one of which was partnering with a new insurance provider for benefits allowing the Company to reduce its benefits premiums while ensuring the continuance and sustainability of the current level of benefits provided to employees. Savings from these measures were incorporated as offsets into the 2016-2020 budgets to the benefit of ratepayers. For further details on Hydro Ottawa's Compensation approach, see Exhibit D-1-8.

Table 3: Summary of Benefits and Pension costs (Appendix 2-K)

Benefits & Pension ($000s)	2012 Actuals	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	CAGR
	$11,536	$12,748	~~$12,856~~	$12,570	$13,354	$14,185	5.3%

2.3 Distribution Operations: Vegetation Management

The costs captured in the Vegetation Management cost driver represent the costs associated with Hydro Ottawa's tree trimming and storm hardening programs. Hydro Ottawa's tree trimming program operates on two and three year cycles for the core and

suburban areas and trim more than 40,000 trees per year. Hydro Ottawa's storm hardening program is a new initiative that began in 2014 and is projected to extend until the end of 2015 and is an adjunct to its normal tree trimming efforts. Hydro Ottawa's storm hardening program was initiated to remove overhang branches over 2,650 spans that are not part of the regular trim cycle and to develop new standards to govern the current trim cycle. The focus on eliminating overhang branches is specifically intended to reduce the risk of outages and equipment damage resulting from weighted, blown or broken overhang branches coming in contact with distribution wires. Moving forward, the elimination of overhang will become part of HOL's tree trimming standards and will be monitored and maintained as a part of its trim cycles. The investments made by Hydro Ottawa in its vegetation management and storm hardening are expected to yield significant long term reliability and productivity benefits. For further details on Hydro Ottawa's storm hardening efforts refer to Exhibit B-1-2(A).

Table 4: Summary of Vegetation Management costs

Vegetation Management ($000s)	2012 Actuals	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	CAGR
	$2,516	$3,074	~~$3,331~~	$4,658	$4,311	$3,507	8.7%

2.4 Distribution Operations: Underground Locates

The costs captured in the underground locates category arise from Hydro Ottawa's compliance with the Ontario Underground Infrastructure Notification System Act ("OUINS Act"). Released in 2012 the OUINS Act requires that members, of whom Hydro Ottawa is one, to respond within five days of notification from the Ontario One Call Corporation to a request for an underground locate.

Hydro Ottawa contracts its underground system locating to a locate contractor. The locate contractor is selected through a competitive bid process where potential contractors are evaluated on price, technical qualifications and performance. Contracts are typically three years in duration but can be extended. Throughout the contract Hydro

Ottawa performs quality assurance audits to verify the number of locates, the locate accuracy and that locates are being performed to Hydro Ottawa's standards.

Costs associated with accommodating underground locate requests are customer demand driven and hence not a cost that is controllable by the company. The table below provides detail as to the historical and forecasted number of locate requests and the actual and estimated average cost per request.

Table 5: Summary of Underground Locate costs

Year	# of Requests *	Total Costs ($000)	Average Cost per Locate ($)
2012 Actual	52,544	$1,622	$30.87
2013 Actual	59,103	$1,861	$31.49
~~2014 Q2 Forecast~~	~~66,847~~	~~$2,010~~	~~$30.07~~
2014 Actual	66,847	$1,980	$29.62
2015 Bridge Year	71,317	$2,216	$31.08
2016 Test Year	79,198	$2,523	$31.86
CAGR		11.7%	

* Requests include office clearances

2.5 Postage Costs

Increased postage rates coupled with Hydro Ottawa's move to monthly billing are the underlying drivers causing an increase to postage costs. To mitigate the impact of the increased postage costs, Hydro Ottawa has initiated a program to encourage its customers to adopt electronic billing or "e-billing". As of December 2014, Hydro Ottawa has approximately 85,991 or 26.9% of its customers subscribed to its e-billing program. Hydro Ottawa estimates an annualized savings of approximately 860K resulting from its move to implement e-billing.

2.6 IT Maintenance

Information Technology maintenance expenses relate to software purchases and upgrades to maintain legacy applications and web interfaces. Examples include the Customer Care and Billing System, AMI/MT, JD Edwards, and data security updates. As noted in Hydro Ottawa's IT Strategy filed in Exhibit B-1-3 legacy applications will be rationalized to simplify ongoing support and maintenance requirements. Continued diligence will be applied to all contracts requiring maintenance and support and efforts will be undertaken to identify where license and service consolidation is possible. As reliance on technology continues to growth through all aspects of the business, the associated IT Maintenance costs also increase.

Table 6: Summary of IT costs

IT Costs ($000s)	2012 Actuals	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	CAGR
	$6,342	$6,659	~~$7,179~~	$7,103	$7,060	$7,616	4.7%

Source: Appendix 2-JC

2.7 Bad Debt

Bad debt results from unpaid account balances. Bad debt continues to be a cost driver because it is an expense that is incurred by Hydro Ottawa that is not entirely within its control. The table below illustrates that bad debt increased in 2013 but is projected to stay relatively flat out to 2016.

Table 7: Summary of Bad Debt costs

Bad Debt ($000s)	2012 Actuals	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	CAGR
	$1,433	$2,182	~~$1,804~~	$1,825	$1,541	$1,979	8.4%

3.0 OM&A PROGRAM COST & VARIANCE ANALYSIS

Pursuant with section 2.7.3 of the OEB's Chapter 2 Filing requirements, the following section provides a variance analysis of Hydro Ottawa's OM&A costs by major program. Table 8 provides historical, bridge and test year expenditures by the program categories and the four year cumulative annual growth rate for each program category. Table 9 provides a year over year analysis of variances per program as expressed both in dollar and percentage terms, the amounts that are highlighted in yellow ~~red~~ denote the variances that exceed Hydro Ottawa's $750K materiality threshold and as such an explanation for the variance is provided. The total program groupings for OM&A are shown net of the allocations to capital programs. Refer to D-1-(F) Attachment F for a description of each program category.

Table 8 - Summary of OM&A Program Costs

Programs	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	CAGR (%)
Reporting Basis								
Collections, Acct & Activities		$2,892,674	$4,068,200	~~$3,642,238~~	$3,687,149	$3,543,341	$4,059,282	9%
Corporate Costs		$6,056,030	$6,575,378	~~$5,420,096~~	$7,346,979	$5,015,524	$4,993,415	-5%
Customer & Community Relations		$7,716,112	$7,573,677	~~$8,087,780~~	$7,338,195	$8,785,231	$9,084,617	4%
Customer Billing		$8,058,100	$8,320,362	~~$10,170,188~~	$10,130,624	$10,333,939	$10,414,125	7%
Distribution Operations		$15,768,787	$16,091,210	~~$17,449,018~~	$17,701,237	$18,705,565	$19,404,972	5%
Engineering & Design		$6,090,200	$6,019,357	~~$6,829,936~~	$6,596,100	$7,585,805	$8,159,989	8%
Facilities		$5,518,926	$5,656,075	~~$5,794,364~~	$5,763,266	$6,027,819	$6,108,573	3%
Finance		$4,074,222	$3,983,782	~~$4,332,691~~	$3,985,949	$4,517,544	$4,759,915	4%
Human Resources & Training		$3,283,630	$3,500,016	~~$3,857,908~~	$3,501,646	$3,945,646	$4,093,085	6%
Information Mgt & Technology		$6,342,125	$6,658,679	~~$7,179,256~~	$7,103,232	$7,060,152	$7,616,378	5%
Metering		$2,384,793	$2,327,873	~~$2,355,505~~	$2,395,501	$2,423,903	$2,532,030	2%
Regulatory Affairs		$1,930,844	$1,967,875	~~$2,340,940~~	$2,045,915	$2,505,096	$2,580,684	8%
Safety, Environment & Bus Cont		$1,853,905	$2,334,564	~~$2,116,845~~	$2,129,185	$1,952,732	$2,006,305	2%
Supply Chain		$1,105,987	$680,108	~~$1,190,652~~	$1,184,017	$1,253,511	$1,292,193	4%
Miscellaneous								
Total	**$73,090,393**	**$73,076,334**	**$75,757,156**	~~**$80,767,417**~~	**$80,908,994**	**$83,655,809**	**$87,105,564**	**4%**

Table 9 - Summary of OM&A Program Variances (in thousands of dollars)

Programs ($000)	2013 - 2012		~~2014 - 2013~~		2014 - 2013		~~2015 - 2014~~		2015 - 2014		2016 - 2015	
Collections, Acct & Activities	1,176	41%	~~(426)~~	~~-12%~~	(381)	-9%	~~(99)~~	~~-3%~~	(144)	-4%	516	13%
Corporate Costs	519	9%	~~(1,155)~~	~~-21%~~	772	12%	~~(405)~~	~~-8%~~	(2,331)	-32%	(22)	0%
Customer & Community Relations	(142)	-2%	~~514~~	~~6%~~	(235)	-3%	~~697~~	~~8%~~	1,447	20%	299	3%
Customer Billing	262	3%	~~1,850~~	~~18%~~	1,810	22%	~~164~~	~~2%~~	203	2%	80	1%
Distribution Operations	322	2%	~~1,358~~	~~8%~~	1,610	10%	~~1,257~~	~~7%~~	1,004	6%	699	4%
Engineering & Design	(71)	-1%	~~811~~	~~12%~~	577	10%	~~756~~	~~10%~~	990	15%	574	7%
Facilities	137	2%	~~138~~	~~2%~~	107	2%	~~233~~	~~4%~~	265	5%	81	1%
Finance	(90)	-2%	~~349~~	~~8%~~	2	0%	~~185~~	~~4%~~	532	13%	242	5%
Human Resources & Training	216	7%	~~358~~	~~9%~~	2	0%	~~88~~	~~2%~~	444	13%	147	4%
Information Mgt & Technology	317	5%	~~521~~	~~7%~~	445	7%	~~(119)~~	~~-2%~~	(43)	-1%	556	7%
Metering	(57)	-2%	~~28~~	~~1%~~	68	3%	~~68~~	~~3%~~	28	1%	108	4%
Regulatory Affairs	37	2%	~~373~~	~~16%~~	78	4%	~~164~~	~~7%~~	459	22%	76	3%
Safety, Environment & Bus Cont	481	26%	~~(218)~~	~~-10%~~	(205)	-9%	~~(164)~~	~~-8%~~	(176)	-8%	54	3%
Supply Chain	(426)	-39%	~~511~~	~~43%~~	504	74%	~~63~~	~~5%~~	69	6%	39	3%
Grand Total	**2,681**	**4%**	**~~5,010~~**	**~~6%~~**	**5,152**	**7%**	**~~2,888~~**	**~~3%~~**	**2,747**	**3%**	**3,450**	**4%**

3.1 Collections, Accounts and Activities

The Collections, Accounts and Activities program captures costs associated with Hydro Ottawa's collection activities and its bad debt expense. Half of the costs are attributable to compensation and benefits and the other half of costs captured in this category are primarily bad debt expense.

Headcount remains flat but compensation will be adjusted per Hydro Ottawa's collective agreement. Bad debt expenses went up in 2013 which resulted in a historical high. With several mitigation strategies, management was able to bring bad debt expense down in 2014 and back to the industry average going forward.

In 2012 bad debt as a percentage of electricity revenue was 0.16% with bad debt expense $1.4M, which is below industry average. In 2013 there was a spike that began in Q3 and resulted in a year end bad debt expense of $2.3M. The spike was explained by the economy downturn and other economic factors compounded by the OEB collections rules on residential and low income customers have added pressure on controlling our bad debt expense. This is not distinct to Hydro Ottawa; it is affecting other LDC's as well. Management reviewed the situation and came up with a number of recommendations to mitigate the impact including account set-up and collection process changes and technology changes (e.g. CC&B configuration changes and functional enhancements). In addition, the deployment of remote disconnected meters improved

the collection process. In 2014, after the implementation of monthly billing, the bad debt decreased by $0.4M or 16% ~~$0.5M or 22%~~. Bad debt expense is projected to be in line with industry average.

3.2 Corporate Costs

Corporate costs category primarily captures management fees from the Holding Company (reference to Exhibit D-3-3), Insurance, Future Employee Benefits (post-retirement benefit), and vacancy allowance budget.

The increase from 2013 to 2014 is due to the one-time credit of ($0.8M) relating to the deposit in the refund account with the group benefits insurance provider.

Corporate Costs is showing a decrease due to the vacancy allowance budgeted in ~~2014,~~ 2015~~,~~ and 2016. Actual vacancies are reflected in each of the program costs for 2012, ~~and~~ 2013 and 2014, only the budgeted amounts are included in corporate costs The vacancy allowance budget is to reflect compensation savings resulting from employee turnover throughout the course of the year. The amount is estimated based on historical trend.

Excluding vacancy allowance, all the major cost components within corporate costs remain steady.

3.3 Customer and Community Relations

Customer and Community Relations program captures costs associated with the salaries and benefits as well as costs associated with the customer experience team, key accounts, customer contact, and communications. Half of the costs are headcount related, the other half includes the external call centre, media communications, and the OEB mandated LEAP Program.

During the reporting period, call volumes increased approximately 12% year over year and customer satisfaction increased to 89% up from 76% to 85%. Overall spending trend was steady with an annual growth rate of approximately 4%. The trend represents costs associated with the call centre volumes resulting from increased media coverage and customer outreach. Call volumes are expected to remain high due to increasing outreach and bill changes. As cost mitigation, Hydro Ottawa has committed to restrain call centre contract costs and will measure the call centre contract activity as part of quarterly productivity scorecard and monthly customer satisfaction performance scorecard.

2014 spending was low due to the resources focus on the implementation of monthly billing and CC&B enhancements, resulting in delays in some program roll-outs. The most notable one is the roll out of the new website. The new website went live in Q2 2015. The importance of the website and its related digital products and services are a critical and an ever-increasing part of our business; especially in the efforts to enhance the customer experience and increase productivity. The increase from 2014 to 2015 is largely economic increases and also 2014 programs deferred to 2015 including customer experience program, media communications, and the new website.

3.4 Customer Billing

Customer billing includes costs associated with Billing, Meter to Cash, and Meter Data operations and staff. Compensation / headcount represents one third of the overall costs.

Compensation / headcount costs are projected to decrease by $0.4M from $3.7M in 2012 to $3.3M in 2016. The decrease is attributed to a forecasted reduction in labour costs with a corresponding increase in technology costs. Customer billing non-compensation costs (mainly technology costs and bill production including postages) are projected to increase at a 13% annual growth rate. The principle driver behind the cost increases are:

Increase to IT costs to support meter data and a post-AMI (Automated Metering Infrastructure) deployment environment which relies on technology to ensure

data and billing accuracy. IT support costs includes Savage data and CC&B to ensure Hydro Ottawa's customers are billed correctly; and

Increase to postage costs due to postage rate increases combined with Hydro Ottawa's move to implement monthly billing. In 2013, the postage rate was $0.61. In 2014, Canada Post increased postage rate to $0.70. This represents 15% increase in postage rate. To mitigate these cost increases, Hydro Ottawa introduced "Go Paperless" and electronic Billing initiatives including MyHydroLink and Autopay. As of December 2014, Hydro Ottawa had approximately 85,991 e-bill accounts representing 26.9% of its customers. Overall OM&A annualized savings due to E-billing program now stand at approximately $860K. Despite the large increase in postage rate and the monthly billing, with its e-billing efforts Hydro Ottawa's postage expenses increased by $0.7M only or 12%.

3.5 Distribution Operations

Distribution Operations includes costs associated with the operations and maintenance of Hydro Ottawa's distribution assets. Programs include Vegetation Management, Underground Locates, Environmental Spills Cleanup, Load Dispatching, and other general maintenance.

Distribution Operations spending increased in 2014 and 2015. The major increases are largely attributable to the following distribution maintenance programs:

Vegetation Management – this is a prevention investment that is designed to produce a long term gain. Our SAIFI caused by tree contacts remain low at 0.05 to 0.12 while the industry average at the range of 0.18 and 0.47 (Source: 2012 CEA Service Continuity Reporting). Trees that contact power lines are one of the major causes of power failure. The increase in spending in 2014 and 2015 is mainly related to the storm hardening programs (reference D-2-1, 3.5), however 2016 is projecting a decrease, as the storm hardening work will be completed beginning of 2015. This program annual spending increased from 2.5M in 2012 to 3.5M in 2016 with an annual growth rate of 9%. Over 80% of the program costs are outside services.

Underground Locates – the costs captured in this program increased significantly following the introduction of Bill 8 (Ontario Underground Infrastructure Notification System Act) which became law in June 2012. The program costs increased from $2.0M in 2012 to $2.9M in 2016, which represents a 12% annual growth rate. Two third of the increases are volume related (customer demand), the remaining one third of the cost increase is due to inflationary cost increase in Hydro Ottawa's contractor with Promark (reference D-2-1, 3.6)

Despite the significant increases in these two programs, overall distribution operations remained within a 5% annual growth rate.

3.6 Engineering and Design

Engineering and Design program includes costs associated with Distribution Design, System Operations (SCADA), Asset Planning, Policies, Procedures, and Standards. Over 80% of the costs are labour costs, remaining 20% are mainly technology costs related to the GIS system, SCADA, and the new asset management software.

Annual growth rate 8% with a spike in 2015 ~~2014~~. It is explained by the increased technology costs for GIS, SCADA, and Asset Management. In addition, the company has conducted a large review of our Conditions of service. This revision is the largest the company has seen, including substantial policy, tariffs and charges review. Furthermore, in keeping with Hydro Ottawa's commitment to provide excellent Customer Service, the document will be revamped to more navigable, understandable and user-friendly. The new version is expected to be published in 2015.

3.7 Other Programs

Other Programs including Facilities, Finance, Human Resources, Information Technology, Metering, Regulatory, Safety, Environmental & Business Continuity, and Supply Chain are all projected to experience minor growth. No major spending variances. Some programs have benefit from the productivity initiatives such as

Metering. With the deployment of remote disconnected meters, field activities reduced, therefore annual growth rate at 2% only.

4.0 CAPITALIZATION OF OVERHEAD OM&A

Table 10 below sets out OM&A by program before capitalization as set out in Appendix 2-D. Hydro Ottawa's capitalized overhead costs are consistent with the OEB's policy on capitalization. Table 11 sets out OM&A that has been capitalized as set out in Appendix 2-D. For details of the Company capitalization policy, please see Exhibit B-5-3. The policy remains the same since 2012 with the percentage capitalized in a range of 25% and 27%.

Table 10 – OM&A by Program before Capitalization

OM&A Before Capitalization	2012	2013	~~2014 Q2 Forecast~~	2014	2015	2016
	Historical Year	Historical Year	~~Historical Year~~	Historical Year	Bridge Year	Test Year
Collections, Acct & Activities	$ 2,937,418	$ 4,070,580	~~$ 3,649,114~~	$ 3,694,025	$ 3,543,341	$ 4,059,282
Corporate Costs	$ 6,056,030	$ 6,575,378	~~$ 5,420,096~~	$ 7,346,979	$ 5,015,524	$ 4,993,415
Customer & Community Relations	$ 7,716,112	$ 7,605,947	~~$ 8,220,736~~	$ 7,462,160	$ 8,785,231	$ 9,084,617
Customer Billing	$ 9,176,802	$ 9,736,344	~~$ 10,664,787~~	$ 10,604,888	$ 10,432,583	$ 10,511,497
Distribution Operations	$ 33,380,038	$ 34,860,050	~~$ 37,834,129~~	$ 38,425,861	$ 39,785,778	$ 40,824,588
Engineering & Design	$ 10,863,198	$ 11,693,463	~~$ 12,451,538~~	$ 11,921,811	$ 12,975,442	$ 13,677,111
Facilities	$ 5,518,926	$ 5,656,285	~~$ 5,794,592~~	$ 5,763,134	$ 6,027,819	$ 6,108,573
Finance	$ 4,074,222	$ 3,988,437	~~$ 4,368,115~~	$ 4,021,373	$ 4,517,544	$ 4,759,915
Human Resources & Training	$ 3,395,830	$ 3,675,121	~~$ 4,010,176~~	$ 3,590,638	$ 4,051,662	$ 4,180,257
Information Mgt & Technology	$ 6,343,145	$ 6,717,794	~~$ 7,521,460~~	$ 7,459,920	$ 7,500,528	$ 7,862,963
Metering	$ 2,712,295	$ 2,807,318	~~$ 2,846,087~~	$ 2,869,959	$ 2,842,465	$ 2,956,322
Regulatory Affairs	$ 1,930,844	$ 1,967,875	~~$ 2,340,940~~	$ 2,045,915	$ 2,505,096	$ 2,580,684
Safety, Environment & Bus Cont	$ 1,853,905	$ 2,334,564	~~$ 2,116,845~~	$ 2,129,401	$ 1,952,732	$ 2,006,305
Supply Chain	$ 2,233,136	$ 1,985,925	~~$ 2,491,808~~	$ 2,327,632	$ 2,498,434	$ 2,744,524
Total OM&A Before Capitalization (B)	$ 98,191,900	$ 103,675,081	~~$ 109,730,424~~	$ 109,663,695	$ 112,434,180	$ 116,350,054

Table 11 – Capitalized OM&A

Capitalized OM&A	2012 Historical Year	2013 Historical Year	~~2014 Q2 Forecast Historical Year~~	2014 Historical Year	2015 Bridge Year	2016 Test Year
Supply Chain	$ 1,127,115	$ 1,305,256	~~$ 1,301,156~~	$ 1,143,039	$ 1,244,923	$ 1,452,331
Supervision	$ 1,831,800	$ 2,157,288	~~$ 1,826,399~~	$ 1,800,435	$ 2,034,276	$ 2,077,315
Engineering	$ 1,996,465	$ 2,815,805	~~$ 2,843,934~~	$ 2,638,519	$ 2,904,091	$ 2,997,522
Fleet	$ 2,613,093	$ 2,593,457	~~$ 2,737,548~~	$ 2,718,734	$ 2,627,424	$ 2,698,352
Labour	$ 17,547,092	$ 19,046,118	~~$ 20,253,970~~	$ 20,453,974	$ 19,967,657	$ 20,018,970
Total Capitalized OM&A (A)	$ 25,115,566	$ 27,917,925	~~$ 28,963,007~~	$ 28,754,700	$ 28,778,371	$ 29,244,490
% of Capitalized OM&A (=A/B)	26%	27%	~~26%~~	26%	26%	25%

File Number:	EB-2015-0004
Exhibit:	D
Tab:	1
Schedule:	3
Page:	1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-JB
Recoverable OM&A Cost Driver Table

OM&A	Last Rebasing Year (2012 Actuals)	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	~~2015 Bridge Year To Q2~~	2016 Test Year	2017	2018	2019	2020
Reporting Basis											
Opening Balance	$ 73.1	$ 73.1	~~$ 75.8~~	$ 75.8	$ 80.9	~~$ 80.8~~	$ 83.7				
Workforce Planning			~~$ 0.2~~		$ 0.6	~~$ 0.3~~	$ 0.4				
Collective Agreement/Annual progressions		$ 1.1	~~$ 1.2~~	$ 1.7	$ 2.3	~~$ 1.3~~	$ 1.4				
Vacancy and Vacancy Allowance			~~$ (1.6)~~		$ (2.1)	~~$ (0.5)~~	$ (0.1)				
Benefits & Pensions		$ 0.1	~~$ 1.7~~	$ 0.6	$ 0.8	~~$ (0.3)~~	$ 1.0				
Vegetation Management		$ 0.4	~~$ 0.3~~	$ 1.5	$ (0.3)	~~$ 0.9~~	$ (0.4)				
Underground Locates		$ 0.2	~~$ 0.1~~	$ 0.1	$ 0.3	~~$ 0.3~~	$ 0.3				
Changes in Capital and Allocations		$ (0.6)	~~$ 0.2~~	$ 0.4	$ (0.4)	~~$ 0.1~~	$ (0.2)				
Postage		$ (0.1)	~~$ 0.7~~	$ 0.8	$ 0.1	~~$ 0.2~~	$ -				
IT Maintenance		$ 0.5	~~$ 1.2~~	$ 1.2	$ 0.4	~~$ 0.4~~	$ 0.5				
Bad Debts		$ 0.8	~~$ (0.4)~~	$ (0.4)	$ (0.3)	~~$ (0.3)~~	$ 0.4				
Inventory Scrap recovery reclass out of OMA		$ -	~~$ 0.8~~	$ 0.6		~~$ -~~	$ -				
Inflation					$ 0.8	~~$ 0.8~~	$ 0.8				
Other Costs/(Cost reductions)	$ -	$ 0.3	~~$ 0.6~~	$ (1.4)	$ 0.6	~~$ (0.3)~~	$ (0.7)				
Closing Balance	$ 73.1	$ 75.8	~~$ 80.8~~	$ 80.9	$ 83.7	~~$ 83.7~~	$ 87.1	$ 89.9	$ 92.8	$ 95.9	$ 99.0

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is requied in Exhibit 4.

2 For purposes of assessing incremental cost drivers, the closing balance for each year becomes the opening balance for the next year.

3 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.

4 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

File Number:	EB-2015-0004
Exhibit:	D
Tab:	1
Schedule:	3
Page:	1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	~~2014 Q2 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year	~~Variance (Test Year vs. 2014 Q2 Forecast)~~	Variance (Test Year vs. 2014 Actuals)	Variance (Test Year vs. Last Rebasing Year (2012 Board-Approved)	2017	2018	2019	2020
Reporting Basis														
Collections, Acct & Activities		$2,892,674	$4,068,200	~~$3,642,238~~	$3,687,149	$3,543,341	$4,059,282	~~$417,045~~	$372,133	$4,059,282				
Corporate Costs		$6,056,030	$6,575,378	~~$5,420,096~~	$7,346,979	$5,015,524	$4,993,415	~~-$426,681~~	-$2,353,564	$4,993,415				
Customer & Community Relations		$7,716,112	$7,573,677	~~$8,087,780~~	$7,338,195	$8,785,231	$9,084,617	~~$996,837~~	$1,746,422	$9,084,617				
Customer Billing		$8,058,100	$8,320,362	~~$10,170,188~~	$10,130,624	$10,333,939	$10,414,125	~~$243,937~~	$283,501	$10,414,125				
Distribution Operations		$15,768,787	$16,091,210	~~$17,449,018~~	$17,701,237	$18,705,565	$19,404,972	~~$1,955,955~~	$1,703,735	$19,404,972				
Engineering & Design		$6,090,200	$6,019,357	~~$6,829,936~~	$6,596,100	$7,585,805	$8,159,989	~~$1,330,053~~	$1,563,890	$8,159,989				
Facilities		$5,518,926	$5,656,075	~~$5,794,364~~	$5,763,266	$6,027,819	$6,108,573	~~$314,209~~	$345,308	$6,108,573				
Finance		$4,074,222	$3,983,782	~~$4,332,691~~	$3,985,949	$4,517,544	$4,759,915	~~$427,224~~	$773,966	$4,759,915				
Human Resources & Training		$3,283,630	$3,500,016	~~$3,857,908~~	$3,501,646	$3,945,646	$4,093,085	~~$235,177~~	$591,439	$4,093,085				
Information Mgt & Technology		$6,342,125	$6,658,679	~~$7,179,256~~	$7,103,232	$7,060,152	$7,616,378	~~$437,121~~	$513,146	$7,616,378				
Metering		$2,384,793	$2,327,873	~~$2,355,505~~	$2,395,501	$2,423,903	$2,532,030	~~$176,526~~	$136,530	$2,532,030				
Regulatory Affairs		$1,930,844	$1,967,875	~~$2,340,940~~	$2,045,915	$2,505,096	$2,580,684	~~$239,744~~	$534,769	$2,580,684				
Safety, Environment & Bus Cont		$1,853,905	$2,334,564	~~$2,116,845~~	$2,129,185	$1,952,732	$2,006,305	~~-$110,540~~	-$122,880	$2,006,305				
Supply Chain		$1,105,987	$680,108	~~$1,190,652~~	$1,184,017	$1,253,511	$1,292,193	~~$101,541~~	$108,176	$1,292,193				
Miscellaneous								~~$0~~	$0	$0				
Total	**$73,090,393**	**$73,076,334**	**$75,757,156**	~~**$80,767,417**~~	**$80,908,994**	**$83,655,809**	**$87,105,564**	~~**$6,338,147**~~	**$6,196,569**	**$14,015,171**	**$89,932,139**	**$92,850,437**	**$95,863,434**	**$98,974,203**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in the miscellaneous line. Add more Programs as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

Balanced Productivity Metrics

HydroOttawa

Audited 2014 Results

	Measures	Description	2011	2012	2013	Q1	Q2	Q3	Q4
Labour Utilization	Productive Time	% of Billable Hours / Total Regular Hours	70%	71%	69%	71%	70%	69%	71%
	Labour Allocation to CAPEX	% of Labour Time on Capital Activities / Total Productive Time	61%	55%	56%	60%	59%	60%	60%
	Average Sick Days per FTE	Total Sick Days / Total Employees	5.3 Days	5.9 Days	6.0 Days	8.0 Days	7.2 Days	6.6 Days	5.9 Days
OM&A Measures	Cost per Underground Locate	Total Underground Locate costs / Total Locate Requests	$27.6	$29.1	$30.0	$36.1	$27.8	$28.0	$28.7
	Vegetation Management Cost Value Metric	Total Vegetation Management Costs / (1 - Tree Contacts SAIFI)	$36K	$24K	$29K	$37K	$34K	$32K	$42K
	Customer Service Cost Value Metric	External Call Centre Costs / Customer Satisfaction %	$28K	$27K	$25K	$26K	$30K	$29K	$28K
	Bad Debt as a % of Total Electricity Revenue	Bad Debt / Total Electricity Revenue	0.18%	0.16%	0.25%	0.28%	0.27%	0.19%	**0.18%**
Asset Efficiency	Sustainment Asset Reliability Cost Value Metric	Asset Replacement and Plant Failure Costs / (1 - Defective Equipment SAIFI)	$433K	$413K	$504K	$217K	$331K	$429K	**$522K**
	Cost per Pole replaced	Planned Pole Replacement Program Costs / # of Poles Replaced	$15K	$20K	$23K	$21K	$21K	$27K	**$32K**
	Cost per metre Cable replaced	Cable Replacement Program Costs / metres of Cables Replaced	$363	$186	$328	$375	$229	$290	**$434**
	Cost per metre Conductors extended	Line Extension Program Costs / metres of Conductors Extended	$67	$61	$136	$60	$94	$97	**$127**
	Technology Infrastructure Cost per Employee	(External IT support costs + computer hardware & software depn) / # of FTE	$21.8K	$21.9K	$22.2K	$16.6K	$19.7K	$20.2K	$21.5K
	Normalized Derecognized Assets net of Proceeds	$ Derecognized Assets net of Proceeds (all companies)	N/A	$0.7M	$2.1M	$0.4M	$0.5M	$0.7M	$0.9M
	Generation Plant Availability	Sum individual plant availabilities / number of generation stations	95.5%	94.5%	95.3%	93.5%	99.1%	88.0%	89.0%
Profitability Metrics	EBITDA as a % Revenue	EBITDA $ / Total Revenue - Generation	70%	59%	64%	68%	69%	68%	67%
		EBITDA $ / Total Revenue - Hydro Ottawa Limited	55%	48%	46%	48%	44%	46%	44%
	Cost per kWh Generated	Total Costs (excluding BD, depn, interest, and taxes) / kWh generated	0.0250	0.0175	0.0247	0.0198	0.0231	0.0233	**0.0239**
	Inventory Turnover Ratio	Cost of Materials Used / Average Inventory	1.70	2.25	2.12	2.13	2.10	2.07	1.83

Narratives

Q4	Q3	
		Labour Utilization
●	▲	Productive Time was up from 2013. Total regular labour hours charged to jobs were up, overtime was down. Field Operators increased chargeable hours from prior year.
●	●	Labour Allocation to CAPEX exceeded budget and prior year. Higher Capex activities offset by lower Work for Others, the most notable shift was at Service Desk.
●	●	Average Sick Days per FTE was down to 5.9 Days. Q4 has improved due to several employees returning to work after a long term absence. The 2014 full-year result has improved slightly from 2013.
		OM&A Measures
●	▲	Cost per Underground Locate was lower than the past two years. However total program costs exceeded budget and prior year actual due to 13% or 8000 more locate requests.
▲	▲	Vegetation Management cost value was up, indicating costs increased larger than SAIFI improvement. 57% increased costs from 2013, partially explained by Storm Hardening. SAIFI 0.049 below 2013 and 10-yr avg.
▲	▲	Customer Service value did well in Q4 - lower costs and higher satisfaction, the full year result was skewed by the negative Q2 result. Overall 88% satisfaction with higher costs than budget and prior year.
●	▲	Bad Debt as a % of Total Electricity Revenue has improved from prior year and first half year, slightly better than the 2013 industry average 0.20%. Bad debt expense exceeded budget by $0.7M.
		Asset Efficiency
▲	▲	Sustainment Asset cost value was up, indicating costs increased larger than SAIFI improvement. 29% increased costs. SAIFI 0.279 below 2013 and 10-yr average (CCRA not considered asset replacement, therefore excluded)
X	▲	Capital program costs were up while the units completed in 2014 were down. The increased costs were explained by increased downtown projects which required additional costs for crane and labour.
●	●	Technology Infrastructure cost per employee was lower than prior years because 2014 did not have a full year of CC&B depreciation included. IT maintenance was up by $1.2M or 22% from prior year.
●	▲	Total Derecognized Fixed Assets $1.7M, offset by $0.8M proceeds. The derecognized fixed assets include $0.5M cables and $0.3M meters. Asset Impairments excluded from this measures.
●	●	Generation Plant Availability 89% due to generation station 2 and grinder shut down for the planned Bronson Bulkhead construction, completed in November.
		Profitability
●	●	Generation EBITDA as a % of Revenue was down due to the planned production shutdown for Bronson Bulkhead construction. EBITDA well exceeded budget and prior year result.
X	●	HOL EBITDA as a % of Revenue was down. The expenses were up by 4% while revenue increased by 2%. The HOL EBITDA below budget and prior year result.
●	●	Cost per kWh Generated lower than prior year. Production was 1% lower than prior year, costs were 8% lower.
▲	●	Inventory Turnover Ratio was down due to increased inventory, mainly cables increased in Q4. Total inventory was up, $9M reported in 2012, $10M in 2013, currently $11M.

CUSTOMER SERVICE STRATEGY (2016 – 2020)

1.0 BACKGROUND - CUSTOMER VALUE AND INNOVATION

At Hydro Ottawa, customer value is at the core of our corporate strategic plan[1]. Hydro Ottawa is committed to delivering value across the entire customer experience by providing reliable, responsive and innovative services at competitive rates.

Hydro Ottawa has been on a Customer Service improvement journey since 2004. Over the past number of years, many initiatives have been put in place and significant progress has been made. These improvements have had a positive impact in a number of areas including achieving Customer Satisfaction levels averaging 87 percent over ten years, as compared to a 76 percent Customer Satisfaction level in 2004; increasing First Call Resolution to an average of 82 percent, as compared to 74 percent in 2007; a 40 percent customer uptake of MyHydroLink (Hydro Ottawa's customer web portal) and a 28 percent adoption rate of Electronic Billing, as of March 31, 2015, to name, but, a few.

Concurrently, Hydro Ottawa has experienced a significant drop in customer complaints and calls, per customer, to the call centre, averaging 1.22 calls per customer in 2005 to an average of 1.03 calls per customer in 2014. During this period, the customer base increased by ~~approximately~~ 40,975 accounts, while call centre volumes reduced by ~~approximately~~ 9,078 calls.

Hydro Ottawa's customer service initiatives have also been recognized within the industry and by customers, alike. ~~For example the:~~ Examples are provided in Table 1:

[1] Corporate Strategic Plan, 2013 Annual Report, Hydro Ottawa Holding Incorporated, Pg. 6

Table 1: Industry Recognition

Year	Industry Recognition
2010	• Chartwell Best Practices Award – Outage Communications • EDA – Customer Service Award Finalist – Outage Communications
2011	• EDA Customer Services Excellence Award – Customer Self Service
2012	• Chartwell – Customer Services Best Practices Award – Runner Up – Customer Self Service
2014	• EDA Communications Excellence Award – Go Paperless Campaign • BOMA – Pinnacle – Customer Service • Chartwell Best Practices Award Ebilling – Customer Service

In 2010, Hydro Ottawa introduced a Customer Service strategy[2]. This strategy initially focused on four areas: Complaint Management, Service Standards, Accuracy and Completeness and Quality. A fifth focus area was subsequently added: Innovation.

By listening to our customers through annual customer satisfaction surveys and other forms of engagement, Hydro Ottawa has delivered innovative customer services such as a ~~2010~~ North American Best Practices award winning Outage Communications solution and additional customer self-serve MyHydroLink enhancements such as “Bill Comparison” and a customer account “Dashboard”.

[2] Customer Service Strategy, Presentation to Enterprise Executive Team, September 15, 2010

In ~~2011~~ 2010, Hydro Ottawa received a Chartwell award for Best Practices in Outage Communications. Building on Hydro Ottawa's success, further automation and communication features were added, including web maps and Twitter updates. Hydro Ottawa continues to validate the outage communications system and has identified further areas for improvement. Hydro Ottawa has implemented efficiency initiatives and has developed business requirement specifications to improve both the customer experience and internal productivity regarding outage communications. For further details and examples, please refer to Exhibit D-1-4, Section 3.2, Customer Service.

In 2012 Hydro Ottawa introduced a Mobile service. This industry leading and award winning initiative allowed Hydro Ottawa's customers to access their billing information through the best of our MyHydroLink web portal features, along with extensive Outage Communication information, all from a mobile device of their choice.

In addition, Hydro Ottawa has implemented many other customer service improvement initiatives including:

1. **Customer Service training** - has been provided to all staff including our field workers. This has included the development and dissemination of "Let's talk electricity" booklets to all employees so that they have relevant company and industry facts at their fingertips.

2. **Customer Care & Billing** (CC&B) – Hydro Ottawa has converted from a de-standardized billing system (PeopleSoft CIS) to a leading utility billing solution (Oracle CC&B).

3. **Monthly Billing** – Hydro Ottawa has transitioned all customers to monthly billing from bi-monthly billing in response to Hydro Ottawa's customer preferences for a more frequent bill cycle and for operational efficiencies.

4. **Electronic Billing** – Hydro Ottawa's customers now have the choice of receiving their bills electronically to their device of choice in place of traditional paper bills. 89,991 customers (28%) as of March 31, 2015 now receive their bills electronically.

5. **Payment Options** - Customers are offered a number of payment options including pay by cheque, bank auto-withdrawal, equal monthly payment, or pay by credit card.

6. **MyHydroLink Web Account Portal** - Customers can control their interface with Hydro Ottawa through MyHydroLink (MHL) - a 24/7 web-based customer preference electronic "dashboard". 126,469 customers (40%) as of March 31, 2015 have registered as MHL subscribers where they can select options such as:

   a) My Electricity Usage

   - Where they can view their electricity consumption with a variety of viewing options i.e., Hourly, Daily, Weekly, Monthly, et cetera.
   - Download My Data – where they can export their data to print, PDF, Excel and Green Button formats for further analysis.

   b) Moving

   - Moving in/moving out instructions can be provided to Hydro Ottawa 24/7 at the customer's convenience.

   c) Payment Methods

   - Preauthorized Payment – where the customer can set up a preauthorized payment arrangement without the need to speak with an agent.
   - Credit Card – where the customer can set up a credit card payment without the need to speak with an agent.

d) My Bill

- E-Billing – the customer has an option to view their bills and have them electronically stored for up to two years.
- Account History – where full billing and payment history is available.
- Predict My Bill – where the customer has the option of receiving predictions of a future bill partway through the billing cycle. Predictions can be requested daily or weekly. This service can help to reduce "sticker shock" and promote conservation.

e) My Profile

- Where customers can *add* and *remove* accounts conveniently.
- Manage Profile – where the customer can manage their own account information, such as their mobile number, name prefix (Mr., Mrs., Ms., Dr., et cetera), email and other social media contact information.

f) My Account Summary

- Account Summary – provides a convenient "at a glance" view of customer-selected account information.
- Bill Comparison – enables the comparison of a customer bill to their other Hydro Ottawa bills identifying variables such as consumption, rates, bill dates, weather, et cetera.
- View Multiple Accounts – enables customer to conveniently search for all associated accounts from one location.

g) *Account Alerts including*:

- **Bill Alert** – an electronic alert requested by the customer when the customer-set threshold has been exceeded during the billing period. For example, if a customer sets a threshold to be alerted when the amount owing within a bill period reaches $50, the customer shall be notified automatically.
- **Consumption Alert** – an electronic alert is sent to a customer when the customer-set threshold has been exceeded during the

billing period. For example, if a customer sets a threshold to be alerted when the consumption within a bill period reaches 600 kWhs, the customer shall be notified automatically.

- **Peak Consumption Alert** - an electronic alert is sent to a customer when the customer-set threshold has been passed within a given billing period. For example, if a customer sets a threshold to be alerted when the peak consumption within a bill period reaches 20%, the customer shall be notified automatically.
- **Payment Reminder Alert** – When chosen by the customer, an electronic alert shall be sent to a customer the day before their bill is due.

7. **Customer Value Performance Metrics** – Hydro Ottawa has developed an extensive list of measures, metrics and targets that report progress against historic trends, with circulation to Executive Management and our Board of Directors.

8. **Operational Notifications** – Hydro Ottawa has undertaken improvements to proactively notify customers regarding tree trimming requirements and planned outages.

9. **Website Improvements** – several navigational improvements have been made to Hydro Ottawa's web site and further enhancements are planned.

10. **Conservation and Demand Management** – many programs have been implemented with excellent results – both from a customer engagement and results perspective. Please refer to Exhibits A-3-1 and Attachment D-5(B) for more details.

11. Community Involvement – Hydro Ottawa has been actively involved as active volunteers and contributors to United Way Ottawa and Christie Lake Kids, among other charitable activities.

12. Industry Involvement – Hydro Ottawa is an active member within the Ontario electricity industry, as a participating member of the Coalition of Large Distributors and the Electricity Distributors Association. In Canada, Hydro Ottawa holds leadership positions within the Canadian Electricity Association (Chair of the CEA Customer Council, Chair of the CEA Distribution Council). In North America, Hydro Ottawa is an active participant and speaker within high profile industry organizations such as CS Week and Chartwell. Through these activities Hydro Ottawa learns and shares best practices so that Hydro Ottawa may continue to be on the leading edge of providing innovative customer services.

2.0 TRANSITIONING FROM CUSTOMER SERVICE TO CUSTOMER EXPERIENCE

With many customer service improvements implemented, in 2012-2013 Hydro Ottawa returned to basics – asking its customers what they would like to see Hydro Ottawa doing. Hydro Ottawa conducted market research and subsequently developed Hydro Ottawa's customer "personas" to help guide future Customer Service priorities.[3] Customer personas have enhanced Hydro Ottawa's understanding of its customer diversity and segments so that their respective needs can be more effectively addressed in future customer service offerings.

Although Hydro Ottawa has been recognized as a Customer Service industry leader, Hydro Ottawa recognizes the need to continually monitor, anticipate and plan for the future. Hydro Ottawa's customers want more. Their expectations are high and will only get higher with forecasted price increases. The customer landscape is changing – customers are more mobile than ever, technology and choice continues to rapidly evolve and social media has become a core fabric in our market. Hydro Ottawa must respond by providing customers with innovative, leading-edge services that continue to meet their evolving needs and expectations.

Concurrently, Hydro Ottawa is focused on empowering every employee to act as an ambassador on behalf of the company in order to deliver "best-in-class" service to customers.

[3] The Customer Persona Research Program, Presentation by the Strategic Counsel, May 2013.

3.0 CUSTOMER EXPERIENCE VISION 2020

Based on input from Hydro Ottawa's customers garnered through the development of the customer personas, market research, customer satisfaction surveys and the Customer Service Strategic Plan, Hydro Ottawa developed a Customer Experience Strategy in Q4 2013 which was anchored by Hydro Ottawa's Customer Experience Vision and applied to the entire company.

Hydro Ottawa's Customer Experience Vision is to be:

- **Easy to do business with**
- **Caring**
- **Efficient**
- **Knowledgeable**

Supporting this Customer Experience vision, Hydro Ottawa has adopted Guiding Principles for Customer Service to address customers stated desire that Hydro Ottawa be Competent, Dependable, Understanding, Good Communicators, Accessible and Responsive.

In response to customer feedback, Hydro Ottawa has transitioned from a "**Customer Service**" to a "**Customer Experience**" focus. Customer Service initiatives typically address transactional items such as: how quickly a telephone is answered, how long an issue took to resolve, et cetera. Customer Experience initiatives take an overall view of how the customer is "feeling" related to the entire experience with the utility, including the transactional elements generally associated with Customer Service.

Some programs already implemented or in progress include Hydro Ottawa's transition to monthly (versus bi-monthly) billing, programs to transition customers to electronic billing, a Strategic Account Management Program and recommendations related to improving Hydro Ottawa's relationships with Developers and Contractors.

Hydro Ottawa is developing a single integrated "whole of company" roadmap for coordination and alignment of all service elements that will impact and improve the customer experience.

4.0 THE CUSTOMER EXPERIENCE IN 2020

By the year 2020, Hydro Ottawa's customer experience will be driven by choice – our customer's choice. Customers will be given options to allow them to be in control and to interact with Hydro Ottawa how and when they want. Customers will see Hydro Ottawa as an organization that is easy to do business with. Hydro Ottawa will be an organization that is customer centric in nature

A key to delivering this experience is transitioning from treating all customers in the same way to serving customers when, where and how they wish to interact with us.

In addition to the many steps, programs, tools and services already in place as outlined previously, by 2020 Hydro Ottawa's customers will:

1. Receive a **simpler, redesigned bill that is easier to understand and unilingual** in their language of choice (English or French)

2. Receive **video messages as a part of their electronic bill** to help keep them up to date on relevant news and information

3. Have the **option of automatically receiving Outage Communication Alerts** to notify them of power outages. They will have the choice of how they wish to be contacted, in the event of a planned or unplanned power outage with relevant information including outage location, estimated time of restoration, crew status, et cetera. Contact options will include email, text and telephone (including times not to call, if selected)

4. Be able to **compare their consumption to other customers** if they wish

5. Have **access to an Energy Calculator** which will allow them to further understand the impact of various end use devices in their home on consumption and pricing

6. For those customers that have adopted a Micro FIT installation – **information to show how Micro FIT energy production is progressing**

7. For Commercial Customers – have **online access to elements used in the calculation of their bills such as Demand, kVA and Power Factor readings**

8. **When contacting our call centre, receive a robust multi-channel experience.** Our call centre will be upgraded to handle the customer's choice of access including; phone, email, text, chat, fax, social media, agent routing and interactive voice response. These upgrades will enable our customers to experience the following benefits:
    a. Quicker access to agents, and where necessary, to subject matter experts;
    b. The option of receiving a call back instead of waiting in a call queue;
    c. Automated access without the need to speak with an agent for common inquiries, such as account balance, due dates, et cetera;
    d. Receive automated reminders (appointments, payment, et cetera).

9. **For Large Key Accounts, experience Hydro Ottawa transitioning from the historic "reactive" mode to a "proactive" account management approach,** with personal attention along with specific account services including enhanced bill service offerings

10. **Encounter an upgraded web experience that will** allow a smooth and seamless interface, including sophisticated search engine technology to enable quick access to desired information

5.0 ACHIEVING HYDRO OTTAWA'S CUSTOMER EXPERIENCE VISION 2020

To achieve Hydro Ottawa's 2020 Customer Experience Vision between the years 2016 - 2020, Hydro Ottawa will invest in selected technologies and processes building upon the foundational steps taken in 2014 and 2015, as outlined in Table 2 below:

Table 2 – Achieving Hydro Ottawa's Customer Experience Vision

Customer Experience Category	Solution	2014	2015	2016	2017	2018	2019	2020
Planning	1) Single Integrated Whole of Company Roadmap							
Technologies	1) CC&B and Monthly Billing							
	2) CC&B Enhancements							
	3) Outage Communications System Upgrade							
	4) MyHydroLink Development and Support							
	5) Oracle Customer Self-Serve							
	6) Customer Relationship Management System							
	7) Avaya CC6							
	7.1) Workforce Automation							
	7.2) Multi-Media							
	7.3) Experience Portal							
	7.4) Rescripting MPS 500							
	7.5) Proactive Outreach Manager							
	7.6) Proactive Outreach for Payments							
	7.7) Call Back Assist							
	7.8) Customer Survey							
	8) Pre Pay Billing							
Process	1) Strategic Account Management Program							
	2) Promoting "Go Paperless"							
	3) Bill Redesign & Unilingual Bills							
~~Foundational Customer Experience Components~~	~~1) Customer Value Analysis~~							
	~~2) Customer Experience Journey Mapping~~							
	~~3) Transactional Surveys~~							
	~~4) Change Management~~							
	~~5) Customer Experience Index~~							
	~~6) Phase 2~~							

Implementation
Planning & Support

5.1 Planning

1. **Single Integrated "Whole of Company" Customer Experience Roadmap** – In 2015 Hydro Ottawa is developing a Single Integrated "Whole of Company" Customer Experience Roadmap that will continue to evolve over time. The objective of this roadmap is to align all parts of the company in the implementation of selected technologies and processes. Items that have been identified to date are outlined below.

5.2 Technologies

1. **Customer Care & Billing (CC&B) and Monthly Billing** – Hydro Ottawa has converted from a de-standardized billing system (PeopleSoft CIS) to a leading utility billing solutions (Oracle CC&B). All customers were transitioned in March, 2014 in response to our customer's preference for a more frequent bill cycle and for operational efficiencies.

2. **CC&B Enhancements** – Hydro Ottawa will continue developing opportunities to further enhance the base CC&B system to ensure that processes continue to meet regulatory requirements and customer's needs (i.e., Landlord Agreement functionality and a number of features to assist with bad debt management, et cetera.)

3. **Outage Communications System** – Hydro Ottawa will upgrade the existing outage communications system to eliminate potential points of failure, while providing premise-based outage reporting (behind a customer preference dashboard) to deliver the information to the customer through their choice of communications medium (i.e., phone, email, text).

4. **MyHydroLink Development and Support** – Hydro Ottawa will continue to support the popular web portal offering and will further enhance this service through further improvements such as:
   a) A "Face lift" (refresh) of the MHL site;

b) Community Compare – Social bench marking, targeting and monitoring which would also be implemented on the mobile site;

c) Basic Energy Calculator;

d) Micro Fit information for customers who are generating electricity;

e) Administrative functionality;

f) Expanded usage information for all commercial customers such as Demand, KVA and Power Factor readings.

5. **Oracle Customer Self-Service (CSS)** – this capability will allow automation of customer web-initiated move ins/outs and account set-up through CC&B without the need to re-key data which will result in productivity gains.

6. **Customer Relationship Management System (CRM)** – provides robust information regarding the customer beyond their billing and payment status. This would be a specific system tailored for Key Account Customers.

7. **Avaya CC6** – A robust, multi-channel customer experience portal that manages phone calls, email, chat, fax, social media, agent routing, Interactive Voice Response (IVR), reporting and analysis. Features include:
   a. **Workforce Optimization** – Automated routing and reporting of assigned work to staff.
   b. **Multi-Media** – Expanding in-bound media options to include Short Message Service ("SMS"), Text, Web Chat and Email. This functionality provides the ability to intelligently route and report on various channels allowing customers to communicate with Hydro Ottawa when and how they wish to do so.
   c. **Experience Portal** – Enhancing IVR technology to offer such services as account balance, due dates, et cetera, through technology, thereby reducing call centre agent volumes.
   d. **Rescripting MPS 500** – providing a more streamlined IVR experience.

e. **Proactive Outreach Manager** – A market leading application to create and manage agent based and automated voice, email, SMS text campaigns and notifications. This feature enables agent-free personalized contacts using any available media type to provide reminders or regular information updates such as account status, confirmation that a customer is home for an installation appointment, appointment rescheduling, payments, fraud notifications, et cetera.

f. **Proactive Outreach for Payment** – Utilizing technology to automate the collections process.

g. **Callback Assist** – Offering callers in queue the option of a callback instead of continuing to wait in queue.

h. **Customer Survey** – The provision of automated customer surveys.

5.3 Processes

1. **Strategic Account Management Program** – a program to transition from a current reactive account management approach to a proactive account management approach.

2. **Promoting "Go Paperless"** – to continually drive postage and paper billing costs down

3. **Bill Redesign & Unilingual Bills** – to address Hydro Ottawa's customers desire to simplify their bills through an easier to understand bill, in the language of their choice (English or French).

WORKFORCE PLANNING STRATEGY

1.0 INTRODUCTION

This schedule describes Hydro Ottawa's workforce planning challenges and discusses the measures being taken by Hydro Ottawa to address these challenges. The workforce planning challenges discussed in this schedule stem largely from shifting workforce demographics resulting from an aging workforce and the need to attract and retain skilled workers to fulfill Hydro Ottawa's corporate priorities including its obligation to safely and reliably deliver electricity to Ottawa residences and businesses.

In its 2012 Cost of Service Application (EB 2011-0054), Hydro Ottawa outlined to the Ontario Energy Board ("OEB") the shifting demographics associated with an aging workforce, and the resulting need to attract and hire additional trades apprentices to off-set expected retirements – an essential requirement to continue enabling asset renewal and reliability programs through a sustained and prepared workforce. Hydro Ottawa further outlined the need to strategically build on its existing workforce by supplementing key support functions with additional resources and expertise to strengthen its capacity to deliver on business priorities tied to operational delivery, compliance and sustainability.

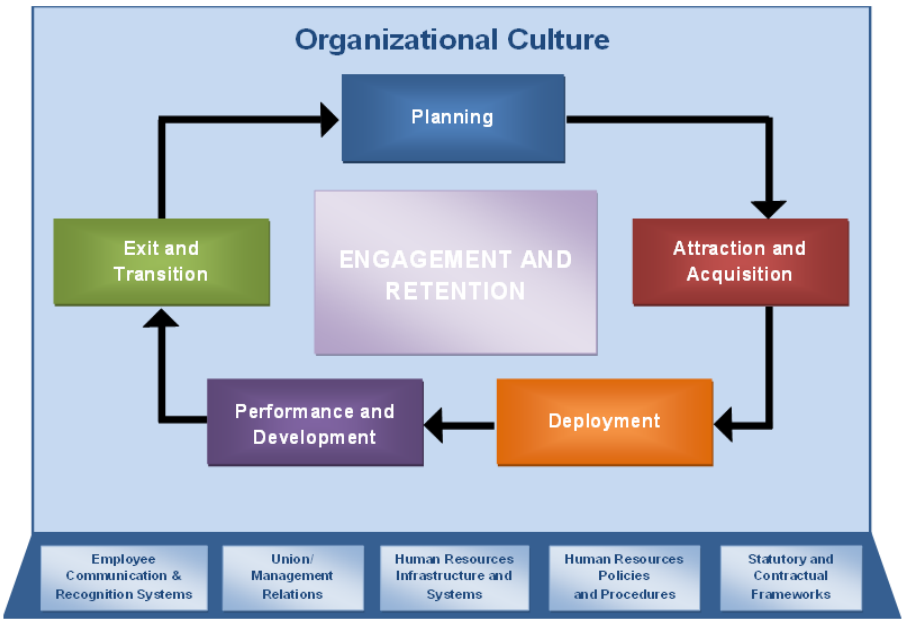
Anticipating and adopting proactive strategies to bridge talent supply gaps is crucial to ensuring a prepared and sustained workforce. Hydro Ottawa depends on a highly skilled, properly trained and knowledgeable workforce to maintain and enhance the reliability of the electricity distribution system, to execute its comprehensive asset management plan, and attend to increasing legislative and regulatory requirements all while addressing customer growth and an evolving customer relationship. Hydro Ottawa's 2016-2020 workforce planning is accordingly guided by current and probable requirements to address the known challenges arising from an aging workforce and infrastructure renewal, as well as the anticipated challenges arising from technological

innovations and an ever-changing business landscape. In what follows, Hydro Ottawa addresses the measures it has implemented to proactively plan for these challenges.

2.0 TALENT MANAGEMENT FRAMEWORK

Hydro Ottawa has leveraged workforce planning, integrated within its Talent Management Framework, to enable business execution into the future and to mitigate the ongoing risk of an insufficient talent pipeline of skilled, prepared and knowledgeable workers. The Talent Management Framework (illustrated in Figure 1 below) provides a comprehensive and integrated human resources management model upon which priorities and initiatives are aligned. The Talent Management Framework centres around five key components of the employee experience in order to build performance and realize potential throughout the talent lifecycle: planning, attraction and acquisition, deployment, performance and development, and exit and transition. The Talent Management Framework is supported by systems that act as a strong foundation of enabling mechanisms.

Figure 1 – Talent Management Framework



Priorities and initiatives under the Talent Management Framework are informed through strategic workforce planning, which assesses changes in workforce demographics and environmental conditions, and responds with talent management approaches. The aim is to ensure operational capacity and continuity by supplying the right talent with the right skills, within the right structure, at the right time. The need to drive innovation and increase productivity has also been integrated into how Hydro Ottawa approaches workforce planning. To this end, workforce planning plays a role in containing costs, creating efficiencies, and in generating added value for our customers. Hydro Ottawa has focused its workforce planning into three areas as follows:

- Workforce Demographics
- Workforce Modeling
- Talent Strategies to Sustain and Prepare the Workforce

3.0 WORKFORCE DEMOGRAPHICS

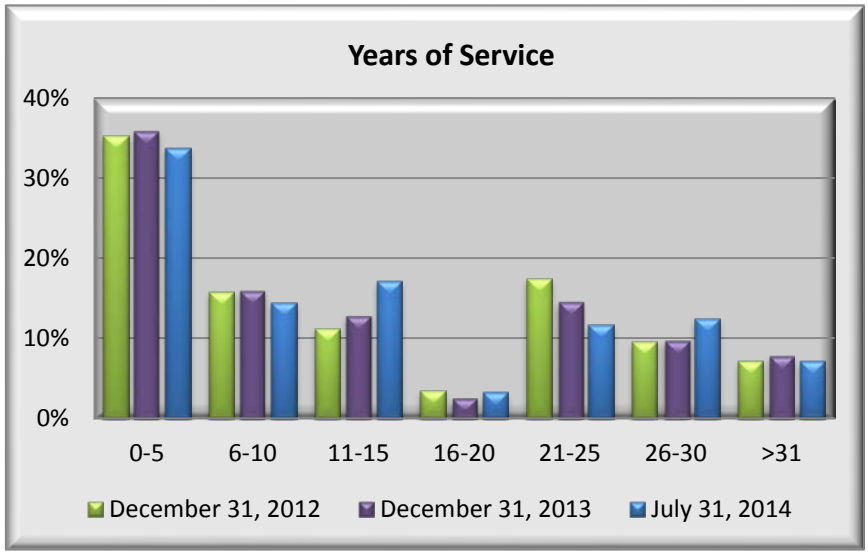
3.1 Aging Workforce

As outlined in the Electricity Sector Council's widely cited "Power in Motion Labour Market Information Study" ("LMI"), the electricity sector is anticipating that an aging workforce will challenge its ability to attract skilled workers into the next several years.[1] The LMI in part attributes these pressures to past hiring trends within the electricity sector, with an influx of skilled workers in the 1970s and 1980s as the legacy distribution system was built. Employment reached record levels in the early 1990s, and then fell in the mid-1990s until the mid-2000s as a result of decreased investments in infrastructure and, in Ontario, because of the amalgamation of local distribution companies. As depicted in Figure 2, Hydro Ottawa's years of service distribution is consistent with this

[1] Electricity Sector Council (now, Electricity Human Resources Canada) works to strengthen the ability of the Canadian electricity industry to meet current and future needs for their workforce, which includes having conducted and disseminated Labour Market Information Studies in 2008 and 2011 (Updated 2012).

historical trend. The average years of service for a Hydro Ottawa employee is 13 years.[2]

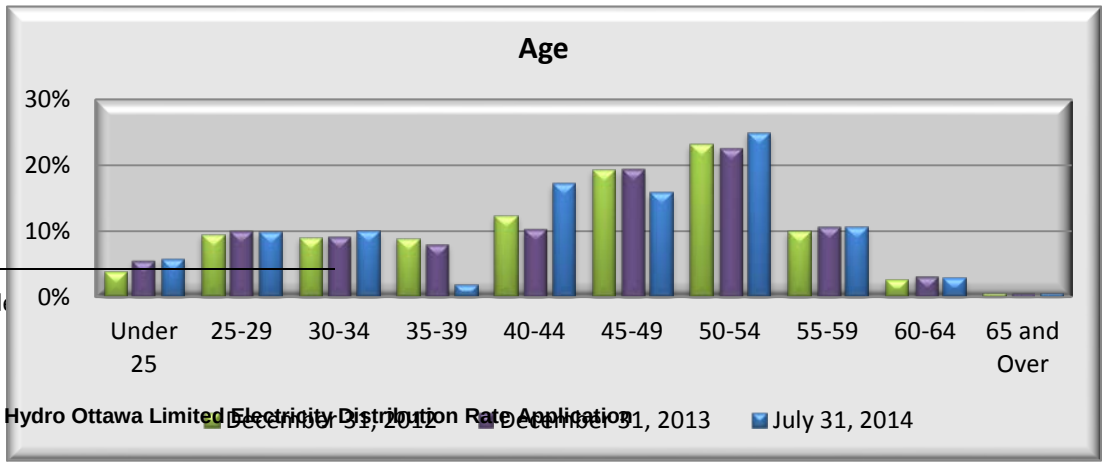
Figure 2 – Years of Service Distribution



The average age of Hydro Ottawa's current workforce is 43, with an overall age distribution depicted in Figure 3. Employees under the age of 30 represent 15.7% of the workforce, an increase from 13.6% since 2012 that is attributable to increased hiring of trades apprentices and engineering graduates since that time.

Employees aged 50 or over represent 39.3% of the workforce, an increase from 32.9% since 2012. The surge of new entrants into the electricity sector, including at Hydro Ottawa, prior to the mid-1990s are now aged 50 plus, reflected by an overall demographic peak for 45-54 year old

Figure 3 – Age Distribution



[2] Unl

3.2 Anticipated Retirement Attrition

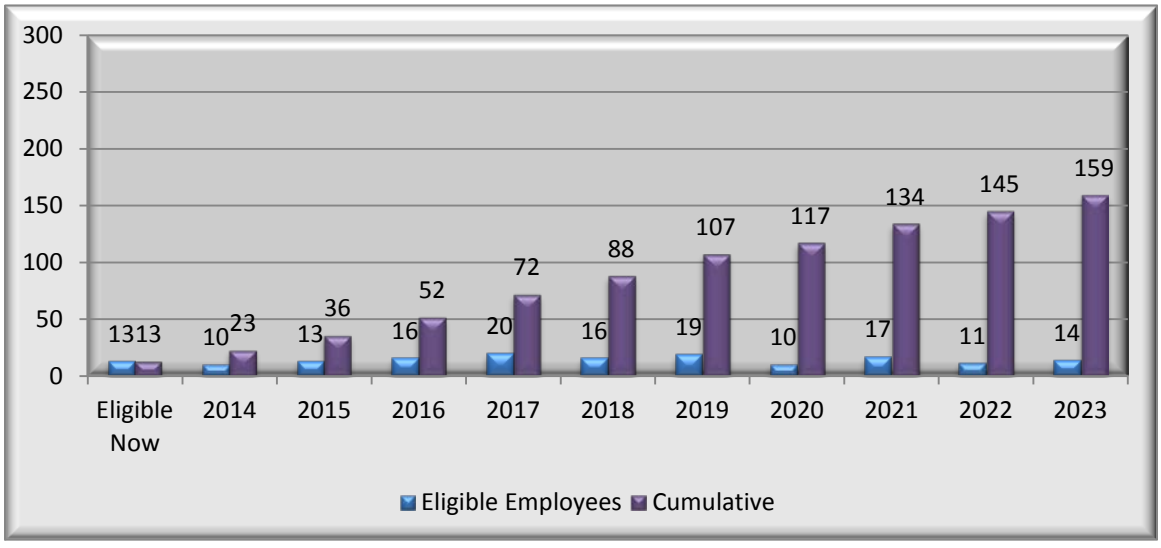
In 2014, Hydro Ottawa began to experience a predicted increase in retirements that is expected to continue into the next ten years as employees elect to retire from the organization at their earliest unreduced eligibility date.[3] On average, employees are retiring at age 59, with 60% retiring within two years of eligibility. The average age of retirement has increased from 57 in 2012, in part attributable to pro-active measures outlined in Section 5.4. This means that employees are choosing to leave the organization at a slightly later age, with 6% of those currently eligible to retire instead choosing to maintain their employment with Hydro Ottawa.

Despite this positive trend, the volume of forecasted retirement eligibility over the next ten years is significant and Hydro Ottawa must effectively address these anticipated departures from the workforce to ensure operational capacity and continuity. Slightly over 40% of Hydro Ottawa's workforce will have become eligible to retire by 2023, of which almost 60% are skilled workers in trades or technical professions. Based on the existing trades and technical workforce, this means that up to 44% of these employees are forecasted to retire by 2023. The number of eligible retirements for all employees is represented in Figure 4, and the eligible retirements in the trades and technical workforce is represented in Figure 5.

[3] Employees are deemed "eligible to retire" for an unreduced early pension based on criteria established under the Ontario Municipal Employees Retirement System ("OMERS").

Figure 4 – Eligible Retirements, All Employees

Figure 5 – Eligible Retirements, Trades and Technical Employees



Over the next ten years, Hydro Ottawa projects the potential loss of approximately 7,693 years of experience from the organization as a result of retirements, including approximately 4,854 years of trades and technical experience. With more than one-third

of the existing workforce population having five years of service or less and the projected retirement of employees, the workforce at Hydro Ottawa is increasingly less experienced in what is an increasingly complex and a safety focused business operating environment. As a result, given that almost half of the existing trades and technical talent within the organization will have reached retirement eligibility within ten years, it is critical that the organization proactively forecast talent demands and anticipated supply gaps early – particularly for positions filled through apprenticeship programs.

Workforce demographic assessments are a key element in Hydro Ottawa's workforce planning approach. Monitoring and planning for retirements in particular is critical to ensuring Hydro Ottawa's continued ability to deliver on its core business objectives with skilled and trained resources.

4.0 WORKFORCE MODELING

A key component of workforce planning, workforce modeling is primarily used at Hydro Ottawa to forecast the supply of labour in relation to operational demand for resourcing. The objective of workforce modeling is to anticipate gaps and inform proactive strategies to address said gaps. The modeling approach provides insight across work segments to identify potential supply gaps based on a number of variables that are validated annually to adjust projected hiring and talent strategies in response to Hydro Ottawa's internal and external environments. Hydro Ottawa's workforce modeling serves to identify the best combination of internal resources, overtime utilization, and contracted services for the delivery of services and programs.

Hydro Ottawa's workforce modeling is leveraged in the deployment of its Distribution System Plan and Asset Management Plan, where prudent cost management efforts require managing the renewal of its distribution system and delivering on daily operating requirements within the resources allocated in capital and operating plans.

4.1 Labour Demand and Supply

Hydro Ottawa's workforce modeling is integrated with operational demand to ensure that forecasting optimally aligns with business requirements by considering projected operational labour requirements.

In order to determine labour supply, Hydro Ottawa's workforce modeling considers the available number of journeypersons or skilled technical employees in a given profession or trade, retirement eligibility, the apprentice pipeline feeding each trade, and supplementary labour resources that contribute to the work undertaken. The modeling is then adjusted based on productive time.

4.2 Retirement Rate

As outlined above, workforce modeling of forecasted retirements assumes that employees will retire at a rate of 60% within two years of reaching retirement eligibility.

4.3 Non-Retirement Attrition Rates

As competition for skilled talent increases due to escalating retirements within the electricity sector at large, Hydro Ottawa's modeling also considers non-retirement attrition due to resignation to be a key variable. Current workforce modeling assumes a non-retirement attrition rate of 2.05% based on 2013 actuals; this rate is adjusted annually, based on the prior year.

4.4 Internal Movements

Hydro Ottawa continues to foster its internal talent pipeline as demographics shift throughout our business, and this results in internal movements of our trades and technical workforce as employees take on leadership roles or grow their professional capacity within our operations in another role. As skilled trades or technical workers leverage their expertise, it is important to proactively anticipate the gaps they leave behind. With this in mind, Hydro Ottawa's workforce modeling assumes that 2.43% of the trades and technical workforce will move laterally or as a result of promotion within

any year. This rate is based on 2013 actuals and is adjusted annually, based on the prior year.

4.5 Modeling Outputs

Based on the above-noted variables, workforce modeling enables Hydro Ottawa to identify its projected gaps in internal labour, and to determine how best to fill these gaps using contracted services, overtime, and/or hiring. Several factors are considered, such as: costs of contracted services or overtime utilization, labour market availability, appropriate ratio of journeypersons to apprentices, legislated allowances for overtime on a per employee basis, and the influence of environmental factors or business considerations that may impact assumptions used to inform modeling.

5.0 TALENT STRATEGIES TO SUSTAIN AND PREPARE THE WORKFORCE

Hydro Ottawa's workforce planning approach serves to inform the organization's talent management priorities and initiatives, including the design of key programs and strategies that emerge or are adjusted to ensure that talent demands are met and sustained.

5.1 Sustaining the Trades

Through structured in-house apprenticeship programs, Hydro Ottawa is revitalizing the trades employee-base to ensure a ready supply of trades talent. Hydro Ottawa has five Apprenticeship Programs in the following trades: Powerline Maintainer, Cable Jointer, Meter Technician, Station Electrician and System Operator. The total number of apprentices is 43, which represents 21% of our trades workforce. The number of apprentices as a proportion of each trade varies from 13% to 33%. Since the introduction of formalized Apprentice Programs in 2005, Hydro Ottawa has enabled 51 apprentices to achieve journeyperson status, representing approximately 29% of the existing trades workforce.

With the anticipated number of retirements over the next ten years, combined with forecasted increases in labour demand as a result of additional work requirements associated with the asset management plan, municipal infrastructure projects, and organic growth in the customer base, Hydro Ottawa expects to continue investing in apprenticeship as a viable source of talent for the skilled trades. To ensure that planned training investments remain prudent and to limit overall headcount increases within the organization as a whole as our trades are replenished, Hydro Ottawa based forecasted hiring on the following principles:

- Increase overall productivity to ensure greater availability of productive time, while also establishing initiatives to gain efficiencies that increase the quality of the time worked.
- Hire apprentices by using vacancies as they become available, including the redistribution of vacancies from support functions to the trades.
- Where available in the labour market, attract and hire journeypersons to fill vacancies, with the aim of reducing the overall required training investment in apprenticeship and leverage qualified resources with a shorter lead time to achieve maximum productivity.
- Balance hiring with the appropriate use of overtime to supplement labour gaps, and continue to leverage contracted services where cost-effective and available to meet demand. These options offer flexibility to Hydro Ottawa in resourcing peak or temporary demands for labour, without unnecessarily inflating the overall workforce complement.

With the application of these principles in mind, Table 1 outlines the forecasted hiring projections for the Powerline Maintainer trade at Hydro Ottawa. In particular, workforce modeling indicates that the demand for labour has the potential to outpace Hydro Ottawa's ability to replenish anticipated retirements, non-retirement attrition, and internal movements from the Powerline Maintainer trade solely through apprentice hiring. In addition to hiring apprentices, Hydro Ottawa will continue to simultaneously attract and

hire qualified Powerline Maintainers at the same rate it has been able to attain in the past few years.

Table 1 – Forecasted Hiring in Powerline Maintainer Trade

	2014 (actual)	2015	2016	2017	2018	2019	2020	Total
Apprentice Hiring	6	5	5	5	5	4	4	34
Journeyperson Hiring	2	2	2	2	2	2	2	14

In anticipation of future hiring requirements within the Powerline Maintainer trade, in 2011, Hydro Ottawa entered into a partnership with Algonquin College to design and deliver a two-year Powerline Technician Diploma Program. Through this Diploma Program, students develop the essential skills and knowledge required to design, plan, construct and maintain electrical distribution lines through class work and hands-on learning. Algonquin College provides theory based courses and leads program administration, while Hydro Ottawa delivers safety and core skills instruction in a practical field environment. This program leverages the skills of experienced Hydro Ottawa Powerline Maintainers, including those who are being developed for leadership roles and those who are nearing retirement or have retired.

As a result of this strategic educational partnership with Algonquin College, Hydro Ottawa has hired 10 Powerline Technician Diploma Program graduates since 2013 when the first cohort completed their program. In doing so, Hydro Ottawa avoided the ongoing costs of intra-provincial apprentice recruitment, and was able to significantly reduce the costs of apprenticeship through a shortened vestibule training period for these hires. This has enabled safe and early field deployment of apprentices to on-the-job learning in the delivery of capital projects.

Forecasting suggests that Hydro Ottawa's remaining trades are appropriately supplied relative to labour demand, and resulting hiring plans focus on replenishing each trade with apprentices based on forecasted attrition. Hiring projections for apprentice hiring in the remaining trades are outlined in Table 2. Due to the specific nature of these trades,

which are not regulated under the *Ontario College of Trades Apprenticeship Act (2009)*, Hydro Ottawa is currently limited in hiring qualified journeypersons from the external labour market for these trades.

Table 2 – Forecasted Apprentice Hiring in Remaining Trades

	2014 (actual)	2015	2016	2017	2018	2019	2020	Total
Cable Jointer			2		2		2	6
Meter Technician		2	2	2	2			8
Station Electrician	3	4						7
System Operator		1	1	2	2	1		7

5.2 Talent Attraction and Acquisition

The Occupational Projection Summary[4] for Electrical Trades and Telecommunications Occupations, over the 2013-2022 period, forecasts that national job openings within this occupational group are expected to total 76,948 (arising from expansion demands and replacement resulting from retirements or mobility) and that 62,002 job seekers (arising from graduates, immigration and mobility) are expected to be available to fill those job openings. The associated analysis establishes an expectation that solid economic growth will translate to a faster increase in the number of Electrical Power Line and Cable Workers (NOC 7244), among other occupations in this group, than the average increase in workers in the rest of the economy. Power System Electricians (NOC 7243) are projected to experience a labour shortage during the projection period. Further, it is expected that the primary source of talent for this occupational group will be from the post-secondary educational system.

The labour market, once driven by employer demand, now hinges on labour supply, making an employer's brand and its ability to attract the best talent possible matter now more than ever before. Hydro Ottawa makes a concerted effort to attract the next

[4] Employment and Social Development Canada's Canadian Occupational Projection System (COPS) develops national job projections and analysis for 140 occupations in Canada.

generation of workers to meet the organization's present and future talent needs by extending our brand through cost-effective social media channels, trades-focused career fairs that reach students at critical junctures in their decision-making about careers, and community outreach to support internationally trained workers in accessing employment. Both co-operative educational placements and a robust summer student program are a valuable source of future employees. Hydro Ottawa also emphasizes strategic partnerships with educational institutions that foster a vibrant and viable talent supply on a sustainable basis, such as the Powerline Technician Diploma Program through Algonquin College and associated applied research opportunities with students in Algonquin's Electrical Engineering Technology program.

In addition to investing in apprenticeships, Hydro Ottawa offers training and development opportunities to attract engineering graduates. The training and development internship for engineering graduates is based on performance-measured deliverables that align with criteria defined by the Professional Engineers of Ontario, and leads to acquisition of the Professional Engineer designation and transition into a Distribution Engineer role at Hydro Ottawa.

Hydro Ottawa also believes it is imperative to attract, retain and develop diverse professionals to spur innovation, drive growth and sustain competitive advantage in the marketplace. Doing so enables Hydro Ottawa to offer additional customer value; create an inclusive culture that leverages diversity in everyday business enhancing engagement and innovation; and broadening involvement to initiatives and organizations that promote diversity, adding a new dimension to Hydro Ottawa's brand. Hydro Ottawa's diversity initiatives focus on attracting and engaging diverse populations represented within the current workforce and its customer communities, including: women, visible minorities, people with disabilities, those who identify as LGBT, and youth. Recognizing the value of immigrant populations within the Canadian workforce and, specifically, as an under-leveraged talent pool within the electricity sector, new Canadians are also considered to be a critical talent segment. Hydro Ottawa's focus on

diversity consists of foundational initiatives intended to foster overall inclusion, complemented by specific initiatives targeted towards the identified diversity groups.

5.3 Strategic Talent Deployment

Hydro Ottawa's approach to talent deployment focuses on the strategic preparation and positioning of new hires and new people leaders in order to achieve reduced time to productivity and value realization, better integration of new hires into company culture, increased retention of new hires and a smoother transition of new people leaders. This approach ensures that new employees are proactively brought on board to replace employees leaving due to retirement or other forms of attrition, and that measures are in place to ensure the transfer of knowledge accumulated by older workers throughout their careers.

As Hydro Ottawa moves into 2016, its approach to strategic talent deployment ensures that resources are provided with optimal leadership and that productivity is enabled by effective organizational design. To this end, and in anticipation of prolonged leadership turnover as the result of retirements, Hydro Ottawa is ever mindful of its responsibility to ensure supervisory spans of control are designed to maximize onsite safety and productivity. Hydro Ottawa is further mindful of the need to yield productivity benefits through consolidation of work, rationalization of headcount for redeployment in trades hiring, and ongoing evaluation of possibilities to outsource work that is not considered to be a core or valued-added aspect of service delivery.

5.4 Knowledge Management and Transfer

With the prospect of losing a significant proportion of experienced workers to retirement over the next ten years, Hydro Ottawa must stem the loss of knowledge unique to the organization through effective knowledge transfer mechanisms. This is consistent with the findings reflected in "Knowledge Management and Transfer for the Electricity Industry in Canada,"[5] which supports mitigating initiatives against the loss of explicit and tacit knowledge within the electricity sector. With specialized skills powering our

[5] Knowledge Management and Transfer for the Electricity Sector in Canada, Electricity Sector Council, 2010

workforce and the risk of losing depth in our corporate knowledge base, Hydro Ottawa recognizes that engaging older workers and retirees is a key consideration in ensuring operational capacity and continuity. As a result, Hydro Ottawa has introduced an initiative aimed at:

- Delaying retirements, where appropriate, to maintain a culture that values experience and supports knowledge transfer opportunities.
- Determining how to best engage employees transitioning into retirement by leveraging ability for hiring overlaps for unique positions and integrating pre-retirement older workers into mentoring programs to enhance knowledge transfer.
- Exploring how retirees can continue to be engaged after retirement and remain Ambassadors in the community which includes establishing a retiree resource pool.
- Reviewing policies, practices and procedures to identify enhancements to better serve older workers and keep retirees engaged.

Branded as Prime Time to reflect that older workers are at the height of their careers rather than at the end, this initiative is in part responsible for increased retention of late-career experienced workers. In 2014 alone, the average age of retirement reached a peak of 60 years.

As part of its Prime Time offerings, Hydro Ottawa continues to support a knowledge transfer overlap to an experienced incumbent retiring from a unique position within the organization. In approving hiring overlaps of this nature, Hydro Ottawa is cognizant that each request must be assessed on a case-by-case to weigh the importance of a specific position to its business operations, the type of knowledge that must be transferred, and the required duration for knowledge transfer to occur. By adopting this methodology, Hydro Ottawa can ensure that the knowledge, skills and corporate memory are passed on to the next generation of the electricity workforce and that this transition is seamless. Without the implementation of knowledge transfer mechanisms, Hydro Ottawa is at risk

of losing significant corporate memory, declines in productivity, compromised business continuity, and losses of intellectual capital.

5.5 Leadership Capability and Capacity

Over the next five years, 35% of Hydro Ottawa's existing people leaders will be eligible to retire, increasing to 57% by 2023. With this in mind, Hydro Ottawa continues to focus on replenishing its talent pipeline through effective succession planning and management activities.

As Hydro Ottawa continues to replenish the leadership pipeline, it also recognizes the sector-wide challenge of increasing overall leadership performance within electricity organizations. The Centre for Creative Leadership's 2009 study on "The Leadership Challenge in the Energy Sector" indicated that the top priority for leadership development into the future is to improve the ability to lead employees with notable skill gaps in building and leading a team, confronting difficult employee situations, building a broad functional orientation and career management.[6]

To strengthen the leadership capability of people leaders, Hydro Ottawa has a comprehensive approach to management and leadership development in which learning progresses from foundational to enrichment to leadership excellence. People leaders and emerging leaders receive targeted development opportunities which are supplemented by a coaching program to accelerate leadership development, in addition to mentorship opportunities with the aim of transferring knowledge cross-functionally and cross-generationally within the business.

6.0 CONCLUSION

Hydro Ottawa will continue to experience the effect of the changing landscape in which it operates, including experiencing the full impact of employee demographics and the

[6] The Leadership Challenge in the Energy Sector, Centre for Creative Leadership, 2009.

associated loss of highly skilled, experienced and knowledgeable employees due to retirements and other attrition. The responses to this rapidly changing environment, if not proactive and meaningful, will inevitably hamper the continued successes of the organization and challenge the organization's ability to fulfill its responsibilities to its customers. Hydro Ottawa must maintain and ensure that the current and future level of its business is sustained throughout these changing times by ensuring that it has a sufficient, sustainable and prepared workforce.

Hydro Ottawa's multi-prong workforce planning efforts are designed to synergistically manage the effects of the dynamically changing electricity industry while ensuring appropriate resources and skills are in place to meet the existing and long-term needs of the business and its customers.

EMPLOYEE COMPENSATION

1.0 INTRODUCTION

This schedule sets out Hydro Ottawa Limited's ("Hydro Ottawa") approach to total compensation and its headcount actuals and projections.

Hydro Ottawa's approach to compensation is driven by the need to attract and retain a highly skilled workforce and to support a performance-driven work culture by appropriately and fairly rewarding performance in the achievement of the company's strategic direction, while at the same time controlling total compensation costs. Hydro Ottawa also rewards performance and productivity in accordance with the company's organizational values and position competencies.

2.0 TOTAL COMPENSATION

Hydro Ottawa's approach to total compensation consists of the following major components which reinforce the total value proposition: salaries, incentive-based pay for senior employees only, benefit plans, pension plan, premiums and allowances.

2.1 Merit-based Salaries

Hydro Ottawa's salary structure for executive, management and non-union employees consists of a number of salary scales representing positions of similar scope and responsibility. A formalized point factor system is in place to evaluate positions and determine the salary scale in which they are placed. This ensures internal equity. Salary scales are reviewed on an ad-hoc basis to ensure competitiveness within the utility, industrial and broader public sectors.

Employees are paid an annual salary within the salary scale based on education and experience. Annual increases to salaries, within the salary scales, are solely merit-based and determined by performance and contributions made in the previous year. A

robust performance management system is in place for this purpose. An overall performance rating is established and a merit increase associated with the rating is provided. Performance and merit increases are directly tied to Hydro Ottawa's corporate performance scorecard, to ensure that the focus of this workforce segment[1] is aligned to the advancement of Hydro Ottawa's strategic direction.

In determining the appropriate range of merit increases associated with each performance rating, Hydro Ottawa reviews the national, provincial and local salary projections of major compensation consulting firms, including those projections for the utility and broader public sectors, as well as consumer price indices.

2.2 Incentive Based Pay

Since 2008, only senior management employees are eligible for annual incentive-based pay, as a component of their total cash compensation, which is expressed as a percentage of annual salary. These employees have a direct line of sight to the success of the company's strategic direction. Approximately 40 or less than 7% of employees are eligible for incentive-based pay in any given year.

Incentive-based pay is determined based on the achievement of financial and non-financial corporate, divisional and individual objectives. Financial targets and non-financial targets for senior management employees are established and approved each year by the Board of Directors and are designed to achieve continuous improvement in relation to the company's strategic direction, which include a number of strategic objectives focused on customer service, operational and organizational efficiency and effectiveness, and service reliability.

Table 1 below demonstrates the variability in this component of total cash compensation as it relates to the achievement of priorities.

[1] Executive, management and non-union employees.

Table 1 – Average Annual Incentive-Based Pay

	2012 Actuals	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
Number of Employees	40	39	37	42	42
Average Amount	$15,825	$17,558	$16,527	$16,358	$16,816

2.3 Collective Agreement

The International Brotherhood of Electrical Workers ("IBEW"), Local 636 represent Hydro Ottawa's unionized employees. This includes the company's trades, technical, clerical and administrative employees.

The current collective agreement is in effect from April 1, 2013 until March 31, 2017. The collective agreement provides for negotiated wage increases and employee step progressions. Negotiated wage increases are 2.6% for 2013, 2.7% for 2014, 2.7% for 2015 and 2.8% for 2016. The wage increases are on average 10% lower than the increases from the previous three year collective agreement.

A number of labour efficiencies were achieved during the most recent round of collective bargaining, some of which directly and indirectly relate to total compensation. These include longer periods of employment for temporary employees, improved distribution of overtime during emergencies, parameters with respect to responsibility pay, the pro-rating of leaves for new employees, the ability to designate specific vacation periods, a simplified process for the relocation of employees for accommodations, rationalization of flame resistant clothing, and an improved process for the replacement of tools and equipment.

2.4 Pension Plan

Hydro Ottawa employees are part of the Ontario Municipal Employees Retirement System ("OMERS"), a multi-employer, contributory, defined benefit pension plan established by the Province for employees of municipalities, local boards and school boards in Ontario. Pension benefits are determined by a formula based on the highest consecutive five-year average of contributory earnings and years of service. Both

participating employers and participating employees are required to make equal contributions to the plan based on the participating employees' contributory earnings.

Employers and employees that are members of the OMERS pension plan contribute a lesser percentage on earnings received up to the annual Yearly Maximum Pensionable Earnings (YMPE), and a higher percentage on earnings above the YMPE. The YMPE is equal to the Canada Pension Plan (CPP) earnings limit as the OMERS pension plan is designed to work together with the CPP to provide a stable retirement income.

Hydro Ottawa's contribution rates to OMERS have steadily increased over the years from 7.4% in 2011 to 9% in 2015 for earnings below the YMPE and from 10.7% to 14.6% for earnings above the YMPE. In an effort to continue to reduce the funding deficit that occurred due to the 2008 global economic downturn, OMERS contribution rates increased in 2012 and 2013 and, due to better returns in 2013, contribution rates have remained unchanged since that time. The OMERS Sponsors Corporation put in place a Funding Management Strategy[2] in late 2014 which limits contribution rate increases at slightly more than 1% higher than the 2014 blended contribution rate. Given the continued deficit position of the OMERS pension plan, it is projected that over the period of this rate application contribution rates will likely increase, both below and above the annual YMPE, for the employee and employer portions respectively.

2.5 Insured Benefits

Hydro Ottawa's insured benefit plans provide employees with income security and protection from catastrophic and life events. Insured benefits coverage is provided to active full-time employees in the following areas:

- Health, including vision care, prescription drugs and paramedical services;
- Dental, including major dental and orthodontics services;
- Long term disability benefits;
- Short term disability benefits; and

[2] As described in *Managing the Benefits and Contributions of the OMERS Primary Plan*, October 27, 2014.

- Life Insurance

As part of the most recent round of collective bargaining in 2013, slight increases in some insured benefit provisions were made, spread out over the four year period of the collective agreement; however, at the same time, further cost containment measures were introduced to supplement those measures already in place, such as reasonable and customary limitations and generic substitution.

In addition, given the increasing costs over the last decade of Hydro Ottawa's insured benefit plans, along with the company's aging demographics, competitive marketing of the plans was undertaken in 2013. In late Q3 of 2014, Hydro Ottawa partnered with a new insured benefits provider for all of the company's insured benefit plans. This change resulted in the reduction of benefits premiums, streamlined administrative processes and enhanced self-serve options while ensuring the sustainability of the current level of benefits.

2.6 Post-Retirement Benefits

Hydro Ottawa's post-retirement benefits consist of life insurance and a small retirement grant for eligible employees primarily linked to positive attendance at work.

Hydro Ottawa completes a full actuarial valuation of the future value of the post-retirement benefits every three years, which is consistent with industry standards. In the interim years, an extrapolation is completed to determine if there has been a material change from the previous year.

The most recent actuarial valuation was performed as at December 31, 2014. A copy of this report is available in Attachment D-1 (B). The valuation determined that the accrued post-retirement life insurance obligation increased from 2013 to 2014, which is primarily attributable to a reduction in the discount rate used in 2014. The accrued retirement grant amount decreased from 2013 to 2014, which is attributable to the retirement of

employees in 2013 that were paid their retirement grant, thereby reducing the company's future obligations.

Hydro Ottawa has taken steps to contain its future benefit costs by limiting the type, scope and applicability of post-retirement benefits.

3.0 HEADCOUNT

Hydro Ottawa has categorized employees/positions into three groups in calculating the total full time equivalents ("FTE"). These groups are comprised of full-time permanent equivalents and temporary equivalents (which can be full-time or part-time)[3].

- Management – includes executives, directors, managers, supervisors and senior professionals such as professional engineers.
- Non-Union – includes non-unionized professionals such as engineers-in-training, budget officers and executive assistants.
- Union – includes all employees who are represented by the IBEW.

The tables below summarize Hydro Ottawa's FTEs for 2012 Actual, 2013 Actual, 2014 ~~Budget Forecast~~ Actual, 2015 Budget Forecast, and 2016 Budget Forecast. Hydro Ottawa's FTE count is determined using standard methodology. For the 2012, ~~and~~ 2013 and 2014 actuals, FTE is a calculated value derived from the total regular hours paid each year divided by the regular hours of work scheduled each year by a single employee in that group. For the ~~2014,~~ 2015 and 2016 forecasted budgets, FTE is calculated as all budgeted positions, adjusted for part-year budgeting for new positions.

3.1 Full-time Permanent Equivalents

Table 2 below illustrates Hydro Ottawa's forecasted plan to stabilize its total number of permanent full-time employees/positions.

[3] Summer students and co-op students are not included as these short term hires are viewed as developmental in nature.

Table 2 – Full-time Permanent Equivalents

	2012 Actuals	2013 Actuals	~~2014 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year
Management	129.1	124.4	~~128.7~~	135.2	132.6	132.6
Non-Union	36.7	44.0	~~42.1~~	41.3	39.7	39.7
Union	417.3	424.6	~~431.2~~	421.1	429.8	429.8
Total	583.1	593	~~602~~	597.5	602.1	602.1

Since 2012, the total number of full-time permanent management and non-union employees combined has remained relatively static. Increases to FTEs ~~have been and~~ are forecasted to be primarily in the union group. In accordance with its Workforce Planning Strategy (Exhibit D1-5-1), Hydro Ottawa is continuing to revitalize the trades employee-base to ensure a ready supply of trades talent to meet operational demand.

The management group FTEs decreased in 2013 versus 2012. This was largely attributable to not filling a number of positions when they became vacant due to employee departures and retirements. Hydro Ottawa employs a stringent vacancy management process to ensure that position replacements or backfills are justified and aligned with its Workforce Planning Strategy (Exhibit D1-5-1). The 2014 ~~forecast~~ actuals show~~s~~ a marginal increase in the total FTE count for the management and non-union groups combined, as a result of the requirement for additional developmental supervisory positions in order to meet safety and operational demand needs.

As Hydro Ottawa moves into 2015 and 2016, its Workforce Planning Strategy (Exhibit D1-5-1) outlines the principles by which it is moving forward in managing overall headcount within the organization as a whole while its trades are replenished by the redistribution of vacancies from support functions.

3.2 Temporary Equivalents

Table 3 below summarizes the number of actual and forecasted temporary equivalents for 2012 to 2016, which includes temporary full-time and part-time resources. In 2013 and 2014, Hydro Ottawa increased its usage of a temporary workforce. This increase in temporary equivalents is attributable to Hydro Ottawa's efforts to have a more flexible

workforce which addresses seasonal and other workloads and can be more easily adjusted upwards or downwards as required. Hydro Ottawa's ~~2014,~~ 2015 and 2016 forecasts continue this approach, allowing the company to contain compensation costs.

Table 3 – Temporary Equivalents (full-time or part-time)

	2012 Actuals	2013 Actuals	~~2014 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year
Management	2.0	2.1	~~2.3~~	0.6	4.8	4.8
Non-Union	6.3	4.9	~~9.5~~	10.6	8.0	8.0
Union	2.0	10.8	~~14.0~~	13.4	7.7	7.7
Total	10.3	17.8	~~25.8~~	24.6	20.5	20.5

3.3 Full-time Permanent and Temporary Equivalents

Table 4 below provides the total number of actual and forecasted permanent and temporary FTEs, and demonstrates Hydro Ottawa's plan to stabilize its workforce.

Table 4 – Full Time Equivalents – Permanent and Temporary

	2012 Actuals	2013 Actuals	~~2014 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year
Management	131.1	126.4	~~131.0~~	135.8	137.5	137.5
Non-Union	43.1	48.8	~~51.6~~	51.8	47.7	47.7
Union	419.3	435.4	~~445.2~~	434.4	437.5	437.5
Total	593.5	610.6	~~627.8~~	622	622.7	622.7

In 2013 there was a net increase of FTEs over 2012. This overall increase is comprised of a reduction in the total FTEs for the management group and an increase in the union and non-union groups. The increase of FTEs in the union group was primarily due to the hiring of additional trades apprentices, journeypersons and technical employees consistent with Hydro Ottawa's Workforce Planning Strategy (Exhibit D1-5-1), as well as the use of more temporary equivalents. The increase in non-union FTEs is largely as a result of an increase in the number of engineers in training.

Table 4 also shows the number of FTEs in the 2015 and 2016 forecasts ~~decreasing~~ remaining flat as compared with the total number of FTEs in the 2014 ~~forecast~~ actuals.

4.0 TOTAL COMPENSATION

Table 5 below summarizes Hydro Ottawa's actual and forecasted total compensation including salary, wages and benefits from 2012 to 2016.

Table 5 - Total Compensation (Salary, Wages, & Benefits)*

	2012 Actuals	2013 Actuals	~~2014 Forecast~~	2014 Actuals	2015 Bridge Year	2016 Test Year
Management	$17,406,925	$17,636,573	~~$19,151,701~~	$18,688,859	$18,986,945	$19,602,474
Non-Union	$4,145,040	$4,778,621	~~$4,973,974~~	$4,853,690	$4,528,497	$4,794,319
Union	$39,353,778	$42,601,466	~~$43,963,563~~	$42,901,556	$45,573,310	$47,547,490
Total	$60,905,742	$65,016,660	~~$68,089,238~~	$66,444,105	$69,088,752	$71,944,283

*Hydro Ottawa has completed Appendix 2-K, Employee Compensation Breakdown, (Attachment AC).

4.1 2013 Actuals versus 2012 Actuals

The total compensation increase from 2012 to 2013 is largely due to the increase in FTEs in the union and non-union groups as discussed in section 3.3 above, as well as an increase in OMERS contributions for 2013 as outlined above in section 2.4.

Additionally, there was an increase in overtime costs in 2013, primarily as a result of the mutual aid provided by Hydro Ottawa trades employees to Toronto Hydro, Hydro One and Hydro One Brampton in response to the restoration efforts arising from the significant ice storm which occurred in the Toronto area and across much of Eastern and Central Ontario in December 2013.

4.2 2014 ~~Forecast~~ Actuals versus 2013 Actuals

The increase in ~~the~~ total compensation ~~forecast~~ for the 2014 actuals versus the actuals for 2013 is attributed to the ~~forecasted~~ increase in total FTEs ~~for all groups~~, in particular, the hiring of additional temporary employees as noted in Table 3 above and the requirement for additional developmental supervisory positions in order to meet safety and operational demand needs, as indicated in section 3.1 above.

4.3 2015 and 2016 Forecast versus 2014 ~~Forecast~~ Actuals

Hydro Ottawa's forecast for 2015 shows a slight decrease in total compensation for the ~~management and~~ non-union group~~s~~ compared to the 2014 actuals ~~forecast~~. For the 2016 forecast, the total compensation for ~~these~~ the management and non-union groups is slightly above the 2014 ~~forecast~~ actuals. This trending demonstrates Hydro Ottawa's commitment to prudently managing the total compensation for the management and non-union groups.

The increase in the 2015 and 2016 forecasted total compensation for the union group is based on the negotiated collective agreement wage increases as per 2.3 above and the revitalization of the trades, via the redistribution of vacancies from support functions, to ensure a ready supply of trades talent to meet operational demand.

The increase in the 2016 forecasted total compensation costs for all groups is also attributable to forecasted increases in benefit and pension costs, given the above noted wage increases and as a result of the expiry of a rate guarantee for certain benefit premiums.

4.4 2017 to 2020 Forecast

Hydro Ottawa's approach to compensation and its plan to stabilize its workforce is anticipated to continue throughout the 2017 to 2020 period. However, Hydro Ottawa must contend during this period with the increasing effects of its aging workforce and the significant volume of forecasted retirement eligibility which must be effectively addressed to ensure operational capacity and continuity. In addition, Hydro Ottawa will be faced with the need to continue planning and responding to the ever-changing business

landscape including the anticipated challenges arising from technological innovations and the evolving and dynamic labour market conditions.

File Number:	EB-2015-0004
Exhibit:	D
Tab:	1
Schedule:	8
Page:	1
Date:	~~ORIGINAL~~ **UPDATED: June 29, 2015**

Appendix 2-K
Employee Costs

	2012 Actuals	2013 Actuals	~~2014 Forecast~~	2014 Actuals	2015 Forecast	2016 Forecast
Number of Employees (FTEs including Temporary)[1]						
Management, including executive	131.1	126.4	~~131.0~~	135.8	137.5	137.5
Non-Union	43.1	48.8	~~51.6~~	51.8	47.7	47.7
Union	419.3	435.4	~~445.2~~	434.4	437.5	437.5
Total	593.5	610.6	~~627.8~~	622.0	622.7	622.7
Total Salary and Wages including overtime and incentive pay						
Management, including executive	$ 14,165,529	$ 14,222,153	~~$ 15,582,458~~	$ 15,199,118	$ 15,241,053	$ 15,648,115
Non-Union	$ 3,365,144	$ 3,830,997	~~$ 4,080,266~~	$ 3,979,888	$ 3,660,815	$ 3,868,504
Union	$ 31,839,026	$ 34,215,448	~~$ 35,569,909~~	$ 34,694,865	$ 36,832,143	$ 38,242,411
Total	$ 49,369,699	$ 52,268,598	~~$ 55,232,633~~	$ 53,873,871	$ 55,734,011	$ 57,759,030
Total Benefits (Current + Accrued)						
Management, including executive	$ 3,241,396	$ 3,414,421	~~$ 3,569,243~~	$ 3,489,741	$ 3,745,892	$ 3,954,359
Non-Union	$ 779,896	$ 947,624	~~$ 893,708~~	$ 873,802	$ 867,682	$ 925,815
Union	$ 7,514,751	$ 8,386,018	~~$ 8,393,653~~	$ 8,206,692	$ 8,741,167	$ 9,305,079
Total	$ 11,536,043	$ 12,748,063	~~$ 12,856,605~~	$ 12,570,234	$ 13,354,741	$ 14,185,253
Total Compensation (Salary, Wages, & Benefits)						
Management, including executive	$ 17,406,925	$ 17,636,573	~~$ 19,151,701~~	$ 18,688,859	$ 18,986,945	$ 19,602,474
Non-Union	$ 4,145,040	$ 4,778,621	~~$ 4,973,974~~	$ 4,853,690	$ 4,528,497	$ 4,794,319
Union	$ 39,353,778	$ 42,601,466	~~$ 43,963,563~~	$ 42,901,556	$ 45,573,310	$ 47,547,490
Total	$ 60,905,742	$ 65,016,660	~~$ 68,089,238~~	$ 66,444,105	$ 69,088,752	$ 71,944,283

Note:

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

Conservation and Demand Management Plan 2015-2020

Attachment D-1(G) contains Hydro Ottawa Limited (as well as Renfrew Hydro)'s approved Conservation and Demand Management Plan for 2015 through 2020, as approved by the Independent Electricity System Operator.

OVERVIEW OF CDM PLAN
This CDM Plan must be used by the LDC in submitting a CDM Plan to the IESO under the Energy Conservation Agreement between the LDC and the IESO The CDM Plan will consist of the information provided in this document and any additional information and supporting documents provided by the LDC to the IESO in support of this CDM Plan. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Energy Conservation Agreement as may be applicable.
Complete all fields within the CDM Plan that are applicable. Where additional space is required to complete a section of the CDM Plan, please append additional pages as required. The LDC should indicate that additional information has been attached in the related question field on the CDM Plan. Please refer to the CDM Plan Submission and Review Criteria Rules for further information.

A. General Information

1.

CDM Plan Submission Date: *(DD-Mon-YYYY)*	1-May-2015
CDM Plan Version	1

2.

LDC INFORMATION										
	LDC 1	**LDC 2**	**LDC 3**	**LDC 4**	**LDC 5**	**LCD 6**	**LCD 7**	**LCD 8**	**LCD 9**	**LCD 10**
LDC Name:	Hydro Ottawa Limited	Renfrew Hydro Inc.								
Company Representative:										
Name:	Roger Marsh	Tom Freemark								
Title:	Chief Energy Management Officer-Hydro Ottawa	President-Renfrew Hydro								
Email Address:	rogermarsh@hydroottawa.com	jtfreemark@renfrewhydro.com								
Phone Number (XXX-XXX-XXXX):	613 738 5499 Ex 342	613 432-4884								

3.

Primary Contact for CDM Plan	
Name:	Bruce Bibby
LDC Name:	Hydro Ottawa Limited
Title:	Manager Conservation and Demand Management
Email Address:	brucebibby@hydroottawa.com
Phone Number (XXX-XXX-XXXX):	613 738 5499 Ex 379

Estimated Start Date of CDM Plan: *(DD-Mon-YYYY)*	1-Aug-2015

LDC CONFIRMATION FOR CDM PLAN	
Each LDC to this CDM Plan has executed the Energy Conservation Agreement.	Yes
A completed Cost-Effectiveness Tool is attached and forms part of the CDM Plan.	Yes
A completed Achievable Potential Tool is attached and forms part of the CDM Plan.	Yes
All customer segments in each LDC's service area are served by the Programs set out in this CDM Plan.	Yes
The CDM Plan includes all electricity savings attributable to all Programs and pilot programs that have in-service dates between Jan 1, 2015 and December 31, 2020.	Yes
The CDM Plan Budget for each LDC includes all eligible funding under the full cost recovery and pay-for-performance mechanisms for Programs under its CDM Plan.	Yes
Frequency of LDC Invoicing to IESO (subsequent changes to the frequency should be notified to us by email).	Quarterly

COMPLETE FOR CDM PLAN AMENDMENTS ONLY		
Select the reason(s) for CDM Plan amendment, as per ECA.		
	One time each calendar year of the term	
	LDC wishes to request an adjustment to the CDM Plan Budget	
	The amendments to a provision of the ECA or any Rules will have a material effect on the CDM Plan	
	LDC's actual spending under CDM Plan has exceeded (or is reasonably expected to exceed) the portion of the CDM Plan Budget allocated to the current year of the term	
	Under a joint CDM Plan, LDCs that are parties to a joint CDM Plan reallocate any portion of their respective CDM Plan Targets and CDM Plan Budgets [*Reallocation not subject to IESO approval*]	
	IESO has triggered remedies under Article 5 of the ECA	
	LDC seeking to change its selection of the type of funding that it wishes to receive for each Program in the CDM Plan [ECA, section 4.1]	
	Other (Please specify reason)	

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Renfrew Hydro Inc.
Company Representative:	Tom Freemark
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	25-May-2015

CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET

		CDM PLAN TOTAL	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LCD 6	LCD 7	LCD 8	LCD 9	LCD 10
a.	**Allocated LDC CDM Plan Target (MWh)** *Indicate total CDM Plan Target allocated to LDC(s)*	**398,710**	394,540.0	4,170.0								
b.	**CDM Plan MWh Savings** *Calculated as part of CDM Plan*	**398,757**	394,573	4,184	0	0	0	0	0	0	0	0
c.	**Allocated LDC CDM Plan Budget ($)** *Indicate total budget allocated to LDC*	**$106,312,729**	$105,242,155.00	$1,070,574.00								
d.	**Total CDM Plan Budget ($)** *Calculated as part of CDM Plan*	**$106,312,728**	$105,242,155	1,070,574	0	0	0	0	0	0	0	0

f.	**CDM Plan Cost Effectiveness** *Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool*		Total Resource Cost (TRC)			Program Administrator Cost (PAC)			Levelized Cost
		Program Year	**Benefits ($)**	**Costs ($)**	**Ratio**	**Benefits ($)**	**Costs ($)**	**Ratio**	**($/kWh)**
		2015	$55,764,480.01	$38,561,858.48	1.4	$48,489,332.53	$1,382,444.10	35.1	$0.001
		2016	$53,854,356.98	$29,017,726.63	1.9	$46,713,248.89	$17,632,866.14	2.6	$0.024
		2017	$56,081,242.02	$27,259,282.19	2.1	$48,648,150.79	$17,314,240.00	2.8	$0.026
		2018	$79,064,316.28	$42,454,281.01	1.9	$68,633,433.36	$21,635,918.56	3.2	$0.032
		2019	$79,719,834.20	$41,725,918.96	1.9	$69,203,448.82	$21,315,758.70	3.2	$0.033
		2020	$79,340,421.05	$40,747,310.47	1.9	$68,873,524.47	$20,739,381.97	3.3	$0.033
		CDM Plan Total	**$403,824,651**	**$219,766,378**	1.8	**$350,561,139**	**$100,020,609**	3.5	

g	**Plan Cost Effectiveness-Exceptions Rationale** *Complete this section if proposed plan <u>does not</u> meet minimum Cost-Effectiveness Thresholds set out in CDM Plan Submission and Review Criteria Rules.*	

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	Hydro Ottawa Limited

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Retrofit			1-Aug-2015			Yes	Yes	Yes	Yes	Yes	$1,332,250	2,144.4	$6,142,186	23,530.4	$6,845,940	27,612.8	$6,077,380	23,530.4	$6,118,828	23,530.4	$6,160,645	23,530.4	$32,677,229	123,878.7
	Heating and Cooling In			1-Jan-2016	Yes	Yes								$3,308,912	3,376.0	$1,743,407	312.0	$1,742,068	312.0	$1,754,737	312.0	$1,797,520	312.0	$10,346,644	4,624.0
	Coupon Program			1-Jan-2016	Yes	Yes								$848,923	2,234.0	$852,955	2,234.0	$852,343	2,234.0	$856,425	2,234.0	$860,543	2,234.0	$4,271,189	11,170.0
	New Construction Program			1-Aug-2015	Yes							$10,000	0.0	$588,780	920.0	$592,408	920.0	$596,855	920.0	$600,685	920.0	$604,550	920.0	$2,993,278	4,600.0
	Home Assistance Proram			1-Jan-2016		Yes								$608,077	784.0	$612,320	784.0	$617,520	784.0	$622,000	784.0	$626,520	784.0	$3,086,437	3,920.0
	Audit Funding Program			1-Jan-2016				Yes	Yes	Yes	Yes			$178,890	759.0	$179,707	759.0	$180,708	759.0	$181,570	759.0	$182,441	759.0	$903,316	3,036.0
	High Performance New Construction			1-Aug-2015				Yes		Yes	Yes	$10,000	0.0	$1,888,110	4,275.0	$1,900,361	4,275.0	$1,915,376	4,275.0	$1,928,313	4,275.0	$1,941,364	4,275.0	$9,583,524	21,375.0
	Process and Systems Upgrades Program			1-Aug-2015						Yes	Yes	$10,000	0.0											$10,000	0.0
	Monitoring and Targeting Program			1-Aug-2015				Yes		Yes	Yes	$10,000	0.0	$225,000	4,200.0									$235,000	4,200.0
	Energy Manager Program			1-Jan-2016				Yes		Yes	Yes			$450,000	5,250.0	$450,000	5,250.0	$450,000	5,250.0	$450,000	5,250.0	$450,000	5,250.0	$2,250,000	26,250.0
			Enhanced Small Commercial Direct Install	1-Jan-2016			Yes							$2,889,320	4,322.0	$3,849,223	6,483.0	$4,191,053	7,204.0	$4,216,925	7,204.0	$3,931,228	6,483.0	$19,077,749	31,696.0
		Conservation Voltage Regulation (CVR) Leveraging AMI Data Pilot		1-May-2015	Yes	Yes	Yes	Yes	Yes	Yes	Yes	$0	5,000.0												5,000.0
			Proposed Conservation Voltage Regulation (CVR) Leveraging AMI Data Program	1-Jan-2016	Yes	Yes	Yes	Yes	Yes	Yes	Yes			$660,000	12,000.0	$800,000	16,000.0	$132,000	0.0	$132,000	0.0	$132,000	0.0	$1,856,000	28,000.0
			Shortfall-Consumer	1-Jan-2018	Yes	Yes												$4,300,103	15,407.0	$4,305,225	15,407.0	$4,310,393	15,407.0	$12,915,721	46,221.0
			Shortfall-Commercial	1-Jan-2018			Yes	Yes	Yes	Yes	Yes							$1,677,990	5,568.0	$1,678,687	5,568.0	$1,679,391	5,568.0	$5,036,068	16,704.0
		Residential Demand Response Wi-Fi Thermostat Pilot		1-May-2015	Yes							$0	20.0												20.0
FCR TOTAL												$1,372,250	7,164.4	$17,788,198	61,650.4	$17,826,321	64,629.8	$22,733,396	66,243.4	$22,845,395	66,243.4	$22,676,595	65,522.4	$105,242,155	330,694.7
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	peaksaverPLUS												0.0												0.0
	Audit Funding												1,138												0
	Bi-Annual Retailer Event												1,656.0												1,656.0
	Conservation Instant Coupon Booklet												578												578
	Direct Install Lighting												7,204												7,204
	Energy Manager (PSUI)												7,350.0												7,350.0
	Heating and Cooling Initiative												3,386												3,386
	High Performance New Construction												855												855
	Low Income Home Assistance Program												784												784
	Monitoring and Targeting (PSUI)												0.0												0.0
	Process and Systems Upgrades Program												20,800.0												20,800.0
	Residential New Construction												920												920
	Retrofit Initiative												20,346.0												20,346.0
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	65,016.6											0.0	63,878.6
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$1,372,250	72,181.0	$17,788,198	61,650.4	$17,826,321	64,629.8	$22,733,396	66,243.4	$22,845,395	66,243.4	$22,676,595	65,522.4	$105,242,155	394,573.3
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 2:	Renfrew Hydro Inc.

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-F	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Retrofit			1-Aug-2015			Yes	Yes	Yes	Yes	Yes	$10,194	50.6	$102,049	470.8	$111,372	521.4	$110,534	521.4	$110,672	521.4	$110,811	521.4	$555,634	2,607.0
	Heating and Cooling			1-Jan-2016	Yes	Yes						$0	0.0	$32,578	40.0	$12,978	2.0	$13,031	2.0	$13,163	2.0	$13,296	2.0	$85,046	48.0
	Coupon Program			1-Jan-2016	Yes	Yes						$0	0.0	$9,989	22.0	$10,030	22.0	$10,069	22.0	$10,107	22.0	$10,144	22.0	$50,339	110.0
	New Construction Program			1-Aug-2015	Yes	Yes						$0	0.0	$4,388	6.0	$4,424	6.0	$4,469	6.0	$4,507	6.0	$4,546	6.0	$22,334	30.0
	Home Assistance Program			1-Jan-2016		Yes						$0	0.0	$8,456	12.0	$8,498	12.0	$8,550	12.0	$8,595	12.0	$8,640	12.0	$42,739	60.0
	Audit Funding Program			1-Jan-2016				Yes	Yes	Yes	Yes														0.0
	High Performance New Construction			1-Aug-2015				Yes		Yes	Yes														0.0
	Process and Systems Upgrades Program			1-Aug-2015						Yes	Yes														0.0
	Monitoring and Targeting Program			1-Aug-2015				Yes		Yes	Yes														0.0
			Enhanced Small Commercial Direct Install	1-Jan-2016			Yes					$0	0.0	$39,865	72.0	$40,110	72.0	$40,411	72.0	$40,669	72.0	$40,930	72.0	$201,985	360.0
			Shortfall-Consumer	1-Jan-2018	Yes	Yes												$30,140	154.1	$30,140	154.1	$23,355	115.5	$83,635	423.7
			Shortfall-Commercial	1-Jan-2018			Yes	Yes	Yes	Yes	Yes							$9,610	32.1	$9,615	32.1	$9,637	32.1	$28,862	96.4
FCR TOTAL												$10,194	50.6	$197,325	622.8	$187,412	635.4	$226,814	821.6	$227,468	821.6	$221,359	783.1	$1,070,574	3,735.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	peaksaverPLUS												0.0												0.0
	Audit Funding												0.0												0.0
	Bi-Annual Retailer Event												17.0												17.0
	Conservation Instant Coupon Booklet												6.0												6.0
	Direct Install Lighting												72.0												72.0
	Energy Manager (PSUI)												0.0												0.0
	Other												0.0												0.0
	Heating and Cooling Initiative												53.0												53.0
	High Performance New Construction												0.0												0.0
	Low Income Home Assistance Program												12.0												12.0
	Monitoring and Targeting (PSUI)												0.0												0.0
	Process and Systems Upgrades Program												0.0												0.0
	Residential New Construction												0.0												0.0
	Retrofit Initiative												289.0												289.0
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	449.0											0.0	449.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$10,194	499.6	$197,325	622.8	$187,412	635.4	$226,814	821.6	$227,468	821.6	$221,359	783.1	$1,070,574	4,184.0
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**	Proposed Conservation Voltage Regulation	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Local Program		
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***	1-Dec-2015		
c.	**Customer Segment(s) Served by Programs**	Residential	Commercial (inc. Multi-Family)	Other
d.	**Participating LDCs** ***(if applicable)***	Hydro Ottawa Limited		
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	This program will utilize the installed smart meters and automated metering infrastructure to provide CVR software with service point voltages to deliver reduced voltage. Operating at reduced voltage will result in lower energy consumption. This program will impact all customer classes.		

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**	Enhanced Small Commercial Direct Install	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Regional Program		
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***	TBD		
c.	**Customer Segment(s) Served by Programs**	Small Business		
d.	**Participating LDCs** ***(if applicable)***	Hydro Ottawa Limited	Renfrew Hydro Inc.	
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	LDC Working Group will be sbmitting the business case for this program.		

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3g. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3h. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3i. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3j. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS				
a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date** ***(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs** ***(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

F. Detailed Information on Collaboration and Regional Planning

ADDITIONAL DETAILED INFORMATION	
Regional LDC(s) Collaboration *Description of how the LDC(s) will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.*	Hydro Ottawa/Renfrew Hydro will continue to work collaboratively with other LDC's in Eastern Ontario in ways such as: french language translation, technical and soft skills training, marketing creatives, and other support as needed. Will also consider collaboration on new program designs.
Gas Collaboration *Description of how the LDC(s) will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.*	Hydro Ottawa/Renfrew Hydro will continue to collaborate with the gas company where possible such as the Home Assistance Program. Any future possibilites will be pursued.
CDM Contribution to Regional Planning *Description of how the CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC(s)' service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.*	Hydro Ottawa's Manager of Energy Conservation and Demand Management actively participates on behalf of both Hydro Ottawa and Renfrew Hydro in regional resource planning meetings in Eastern Ontario. The objective of this participation is to make other participants aware of the contribution of the CDM Plan towards overall resource requirements and to consider CDM in the IRRP process as a first alternative to meet resource needs. We will work to gain alignment between the CDM Plan and commitments required as part of the IRRP. This work will be resourced by CDM engineering and support staff.

G. Additional Documentation for CDM Plan (If applicable)

ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs*	Assumption summary provided.
Approved Local and/or Regional Programs and Pilot Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs*	Included in the assumptions summary provided.
Proposed Local and/or Regional Programs and Pilot Programs *Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs*	Included in the assumptions summary provided.
Programs from 2011-2014/2015 CDM Framework *Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs*	Used historical performance, therefore no additional information required.
Programs funded through Pay-for-Performance *Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs*	n/a
Other *Additional assumptions used in the CDM Plan*	n/a

SHARED SERVICES AND CORPORATE COST ALLOCATION

1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") provides and receives services to/from its affiliated companies Energy Ottawa Inc. ("Energy Ottawa") and Hydro Ottawa Holding Inc. (the "Holding Company"), in order to realize economies of scale, manage costs and maintain service levels.

Hydro Ottawa is the largest entity within the Hydro Ottawa Group of Companies, contributing approximately 90 percent of the revenues and assets. With the exception of strategic Management Services, Internal Audit, Legal, Treasury and Enterprise Risk Management services from the Holding Company, Hydro Ottawa maintains its own resources for the shared corporate services of Human Resources ("HR"), Information Technology ("IT"), Facilities, Supply Chain, Building and Facilities Support, Fleet, Communications, Conservation, Regulatory and Finance services. While the affiliates also have some resources of their own, Hydro Ottawa does provide certain shared corporate services to Energy Ottawa and the Holding Company.

The Holding Company provides shared corporate services such as strategic direction and oversight to Hydro Ottawa in the areas of Finance, Treasury, Internal Audit, Risk Management, Legal, Regulatory, Corporate Administration, Human Resources, Safety & Environment, Information Technology, Corporate Communications and Management Services. Some Board of Directors related costs are also included in the cost allocation to Hydro Ottawa following corporate governance reforms implemented on December 1, 2014, described later in this exhibit.

Furthermore, both Hydro Ottawa and the Holding Company allocate the cost of shared corporate services to Conservation Demand Management ("CDM"), according the fully-allocated costing methodology for non-rate-regulated activities described in the

Conservation and Demand Management Code for Electricity Distributors, September 16, 2010.

2.0 SHARED SERVICE MODEL

Hydro Ottawa's shared service methodology has not changed since the last rate application in 2012, except for the inclusion of Treasury Services and Board of Directors related costs described later in this section.

In accordance with the *Affiliate Relationships Code for Electrical Distributors and Transmitters*, the prices for the shared corporate services are determined by fully-allocated cost-based pricing, with the exception of Meter Data Service Provider costs which are based on market pricing. The pricing models and methodology were developed internally and the services are provided under the terms of Service Level Agreements ("SLA").

Table 1 below identifies the functional services provided by Hydro Ottawa to its affiliates and describes the pricing methodology used for each functional service.

Table 1: Pricing Methodology for services provided by Hydro Ottawa

Functional Service	Pricing Methodology
Human Resources	Cost per employee
Facilities	Market rate for rent, proportionate share of cost for operations and maintenance, property taxes, and furnishings
IT Services	Cost per employee
Finance	Proportionate share of cost factored by time spent
Communications	Proportionate share of cost factored by time spent
Metering, Meter Data Services	Market based
Mechanic Services	Internal labour rate factored by time spent

Table 2 identifies the management services received by Hydro Ottawa from the Holding Company and describes the pricing methodology used for each Management service.

Table 2: Pricing Methodology for services received from the Holding Company

Management Service	Pricing Methodology
Legal, Corporate Administration & Regulatory	Proportionate share of cost factored by time spent
Finance, Internal Audit & Enterprise Risk Management	
HR, Safety & Environment	
Corporate Communications	
Information Management & Technology Services	
Management Services	
Conservation	
Treasury Services	Proportionate share of cost based on borrowing activity
Board of Directors	Proportionate share of cost

The Holding Company costs are allocated to all affiliates based on an assessment of the budgeted costs in relation to activity level within each affiliate and the proportionate share of time spent. This assessment is completed annually to determine the appropriate allocation of costs. At year end, the allocations are reviewed and any material differences between actuals and budget are adjusted through a true up process to ensure costs are properly allocated to affiliates and to non-rate regulated activities.

The range of services provided and received by Hydro Ottawa to and from its affiliates is reviewed annually and adjusted to take into account changing circumstances. Since the 2012 rate application, the following new services have been added to the Service Level Agreements.

- Treasury administration services provided by the Holding Company were consolidated under the umbrella of the SLAs starting in 2012 in order to improve efficiency and transparency around the costs related to borrowing activities and maintaining credit ratings/credit facilities. The costs related to treasury administration services are allocated to affiliates based on their level of borrowing activity.
- Communications services provided by Hydro Ottawa to Energy Ottawa and to CDM were added to the allocations starting in 2013.
- Fleet costs associated with the CDM van provided by Hydro Ottawa were also added to the allocations starting in 2013.

- Certain governance reforms were implemented effective December 1, 2014 in order to achieve a more efficient and cost effective governance structure. The Boards of Directors of the Holding Company and Hydro Ottawa were reconfigured to reduce the duplication and redundancy that existed with the two boards. The Hydro Ottawa Board was reduced from its previous size of seven members to a board of three members, composed of the Chair of the Holding Company Board, the President and Chief Executive Officer of the Holding Company, and one member of management of Hydro Ottawa who is not employed by an affiliate. The Chair of the Holding Company Board and the President and Chief Executive Officer of the Holding Company also serve on the reconfigured eleven-member Holding Company Board. As a consequence of these reforms, all costs related to the Board of Directors are now budgeted under the Holding Company and a proportion of the cost is allocated to Hydro Ottawa through the SLAs starting in 2015. This has resulted in a net reduction of cost to Hydro Ottawa of approximately $40,000 annually.

Table 3: Board of Directors-Related Costs before and After Governance Reform

	Annual Cost
Board of Directors cost before	$160,000
Board of Directors cost after	$120,000
Reduction in Cost due to Governance Reform	($40,000)

3.0 SERVICES PROVIDED TO AND FROM AFFILIATES

A copy of OEB Appendix 2-N is reproduced at the end of this Exhibit for reference. This appendix provides cost information and allocation details relating to each shared service provided or received by Hydro Ottawa in the historical years (2012 to 2014), the bridge year (2015) and the test year (2016). The amount of Board of Directors related costs included in the Holding Company's allocation to Hydro Ottawa in the years 2015 and 2016 is also provided in this appendix.

Table 4 provides a summary of the services provided by Hydro Ottawa to its affiliates and to non-rate regulated CDM activities.

Table 4: Summary of Shared Corporate Services provided by Hydro Ottawa

Provided By	Provided To	2012 Actual	2013 Actual	~~2014 Q2 Forecast~~	2014 Actual	2015 Bridge Year	2016 Test Year
Hydro Ottawa	Holding Company[1]	$743,921	$771,477	~~$785,029~~	$779,165	$818,932	$835,388
Hydro Ottawa	Energy Ottawa[1]	$532,668	$983,140	~~$989,715~~	$976,273	$1,043,155	$1,061,482
Hydro Ottawa	CDM[2]	$292,962	$433,950	~~$437,837~~	$443,071	$455,664	$464,836
Total		**$1,569,551**	**$2,188,567**	**~~$2,212,581~~**	**$2,198,509**	**$2,317,751**	**$2,361,706**

[1] Represents the costs allocated to the Holding Company and Energy Ottawa, which are reflected as Other Revenue in Exhibit C-2-1.

[2] The costs allocated to CDM are treated as an offset to OM&A.

Table 5 provides a summary of the services received by Hydro Ottawa from its parent Holding Company.

Table 5: Summary of Shared Corporate Services received by Hydro Ottawa

Provided By	Provided To	2012 Actual	2013 Actual	~~2014 Q2 Forecast~~	2014 Actual	2015 Bridge Year	2016 Test Year
Holding Company	Hydro Ottawa	$3,501,812	$3,454,602	~~$3,626,081~~	$3,204,847	$3,646,744	$3,720,040
Holding Company	CDM	$156,200	$155,398	~~$173,917~~	$155,153	$173,256	$176,736
Total		**$3,658,012**	**$3,610,000**	**~~$3,799,998~~**	**$3,360,000**	**$3,820,000**	**$3,896,776**

4.0 VARIANCE ANALYSIS

Table 6 and Table 7 below identify the variances for the following:

- 2016 Test Year vs 2012 Actual
- 2016 Test Year vs ~~2013~~ 2014 Actual

Explanations for significant variances are provided after the tables.

Table 6: 2016 Test Year vs 2012 Actual

Provided By	Provided To	2012 Actual	2016 Test Year	$ Variance	% Variance
Hydro Ottawa	Holding Company	$743,921	$835,388	$91,467	12%
Hydro Ottawa	Energy Ottawa	$532,668	$1,061,482	$528,814	99%
Hydro Ottawa	CDM	$292,962	$464,836	$171,874	59%
Holding Company	Hydro Ottawa	$3,501,812	$3,720,040	$218,228	6%
Holding Company	CDM	$156,200	$176,736	$20,536	13%

The $528,814 variance between 2012 Actual and 2016 Test Year for services provided by Hydro Ottawa to Energy Ottawa is due to an increase in the activities of the affiliate. In late 2012, Energy Ottawa acquired three additional hydroelectric plants and additional interest in the Ring Dam and remaining water rights at Chaudière Falls, increasing its number of employees from 14 before the acquisition to 36 after the acquisition. The cost of the various corporate services provided by Hydro Ottawa was reassessed in 2013 to take into account the additional volume of work and time spent in support of Energy Ottawa. The allocations for HR and IT services were both impacted significantly as they are based on cost per employee.

The $171,874 variance between 2012 Actual and 2016 Test Year for services provided by Hydro Ottawa to CDM is primarily due to increase in HR and IT services required to support additional CDM employees and new cost allocations for Communications Services and Fleet introduced in 2013, as described earlier in this Exhibit.

The $218,228 variance between 2012 Actual and 2016 Test Year for services provided by the Holding Company to Hydro Ottawa include inflationary increases and the new allocation for Board of Directors-related costs starting in 2015 as described earlier. These increases are partially offset by a reduction in proportionate share of Treasury

services to 67% as greater effort will be focused on borrowing activities for Energy Ottawa capital works planned.

Table 7: 2016 Test Year vs ~~2013~~ 2014 Actual

Provided By	Provided To	~~2013~~ 2014 Actual	2016 Test Year	$ Variance	% Variance
Hydro Ottawa	Holding Company	~~$771,477~~ $779,165	$835,388	~~$63,911~~ $56,223	~~8%~~ 7%
Hydro Ottawa	Energy Ottawa	~~$983,140~~ $976,273	$1,061,482	~~$78,342~~ $85,209	~~8%~~ 9%
Hydro Ottawa	CDM	~~$433,950~~ $443,071	$464,836	~~$30,886~~ $21,765	~~7%~~ 5%
Holding Company	Hydro Ottawa	~~$3,454,602~~ $3,204,847	$3,720,040	~~$265,438~~ $515,193	~~8%~~ 16%
Holding Company	CDM	~~$155,398~~ $155,153	$176,736	~~$21,338~~ $21,583	~~14%~~ 14%

The $515,193 variance between 2014 Actual and 2016 Test Year for services provided by the Holding Company to Hydro Ottawa is partially due to the fact that the actual expenses of the Holding Company were low in 2014 relative to past trends, as a result of some staff vacancies and reduced requirements for consulting and legal services.

All of the other variances between ~~2013~~ 2014 Actual and 2016 Test Year are consistent with previous explanations and general inflationary cost increases.

5.0 RECONCILIATION OF REVENUE IN APPENDIX 2-N

The Board's Filing Requirements require applicants to provide a reconciliation of the revenue in Appendix 2-N to the amounts included in Other Revenue in Exhibit C-2-1.

Table 8 summarizes the costs allocated by Hydro Ottawa to the Holding Company and Energy Ottawa which are included in Other Revenue.

Table 8: Revenues from Affiliates Included in Other Revenue

Provided By	Provided To	2012 Actual	2013 Actual	~~2014 Q2 Forecast~~	2014 Actual	2015 Bridge Year	2016 Test Year
Hydro Ottawa	Holding Company	$743,921	$771,477	~~$785,029~~	$779,165	$818,932	$835,388
Hydro Ottawa	Energy Ottawa	$532,668	$983,140	~~$989,715~~	$976,273	$1,043,155	$1,061,482
Total		**$1,276,589**	**$1,754,617**	**~~$1,774,744~~**	**$1,755,438**	**$1,862,087**	**$1,896,870**

6.0 BOARD OF DIRECTORS COSTS

The Board's Filing Requirements also require applicants to identify any Board of Director-related costs for affiliates that are included in its own costs. Hydro Ottawa confirms that there are no Board of Directors costs for affiliated entities included in its costs.

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2012 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	**To**			**$**	**$**
HOL	HOHI	Human Resources	Cost	101,512	101,512
HOL	HOHI	Facilities	Market/Cost	236,441	151,683
HOL	HOHI	IT Services	Cost	187,005	187,005
HOL	HOHI	Finance	Cost	136,951	136,951
HOL	HOHI	Communications	Cost	82,012	82,012
Total Charged from HOL to HOHI				**743,921**	**659,163**
HOL	Energy Ottawa	Human Resources	Cost	58,889	58,889
HOL	Energy Ottawa	Facilities	Market/Cost	64,649	49,248
HOL	Energy Ottawa	IT Services	Cost	112,972	112,972
HOL	Energy Ottawa	Finance	Cost	111,894	111,894
HOL	Energy Ottawa	Metering, Meter Data Services	Market	81,720	*
HOL	Energy Ottawa	Mechanic Services	Cost	102,544	102,544
Total Charged from HOL to Energy Ottawa				**532,668**	**435,547**
HOL	CDM	Human Resources	Cost	59,058	59,058
HOL	CDM	Facilities	Market/Cost	40,104	28,375
HOL	CDM	IT Services	Cost	119,853	119,853
HOL	CDM	Finance	Cost	73,947	73,947
Total Charged from HOL to CDM				**292,962**	**281,233**

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	**To**			**%**	**$**
HOHI	*HOL*	Legal, Corporate Admin & Regulatory	Cost	50%	219,461
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgmt	Cost	65%	1,587,467
HOHI	HOL	Treasury	Cost	100%	348,000
HOHI	HOL	HR, Safety & Environment	Cost	95%	541,666
HOHI	HOL	Corporate Communications	Cost	20%	152,095
HOHI	HOL	Information Management & Technology Services	Cost	45%	189,041
HOHI	HOL	Management Services	Cost	46%	464,082
Total Charged from HOHI to HOL					**3,501,812**
HOHI	CDM	Management Services	Cost	50%	156,200
Total Charged from HOHI to CDM					**156,200**

Note:

1 This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2013 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	**To**			**$**	**$**
HOL	HOHI	Human Resources	Cost	110,004	110,004
HOL	HOHI	Facilities	Market/Cost	226,576	142,272
HOL	HOHI	IT Services	Cost	189,949	189,949
HOL	HOHI	Finance	Cost	162,933	162,933
HOL	HOHI	Communications	Cost	82,015	82,015
Total Charged from HOL to HOHI				**771,477**	**687,173**
HOL	Energy Ottawa	Human Resources	Cost	171,068	171,068
HOL	Energy Ottawa	Facilities	Market/Cost	74,745	56,217
HOL	Energy Ottawa	IT Services	Cost	303,040	303,040
HOL	Energy Ottawa	Finance	Cost	182,455	182,455
HOL	Energy Ottawa	Communications	Cost	33,771	33,771
HOL	Energy Ottawa	Metering, Meter Data Services	Market	79,760	*
HOL	Energy Ottawa	Mechanic Services	Cost	138,301	138,301
Total Charged from HOL to Energy Ottawa				**983,140**	**884,852**
HOL	CDM	Human Resources	Cost	88,304	88,304
HOL	CDM	Facilities	Market/Cost	49,224	34,008
HOL	CDM	IT Services	Cost	152,476	152,476
HOL	CDM	Finance	Cost	111,602	111,602
HOL	CDM	Communications	Cost	24,144	24,144
HOL	CDM	Fleet	Cost	8,200	8,200
Total Charged from HOL to CDM				**433,950**	**418,734**

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	**To**			**%**	**$**
HOHI	HOL	Legal, Corporate Admin & Regulatory	Cost	50%	178,863
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgmt	Cost	69%	1,551,912
HOHI	HOL	Treasury	Cost	88%	311,000
HOHI	HOL	HR, Safety & Environment	Cost	95%	564,055
HOHI	HOL	Corporate Communications	Cost	20%	162,196
HOHI	HOL	Information Management & Technology Services	Cost	45%	164,980
HOHI	HOL	Management Services	Cost	46%	521,596
Total Charged from HOHI to HOL					**3,454,602**
HOHI	CDM	Management Services	Cost	50%	155,398
Total Charged from HOHI to CDM					**155,398**

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2014 ~~Forecast~~ Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	~~2014 Forecast~~	~~2014 Forecast~~	2014 Actual	2014 Actual
From	To			~~Price for the Service~~	~~Cost for the Service~~	Price for the Service	Cost for the Service
				~~$~~	~~$~~	$	$
HOL	HOHI	Human Resources	Cost	~~115,441~~	~~115,441~~	115,039	115,039
HOL	HOHI	Facilities	Market/Cost	~~227,148~~	~~147,367~~	222,353	147,367
HOL	HOHI	IT Services	Cost	~~192,840~~	~~192,840~~	192,171	192,171
HOL	HOHI	Finance	Cost	~~164,126~~	~~164,126~~	164,128	164,128
HOL	HOHI	Communications	Cost	~~85,474~~	~~85,474~~	85,474	85,474
Total Charged from HOL to HOHI				**~~785,029~~**	**~~705,248~~**	**779,165**	**704,179**
HOL	Energy Ottawa	Human Resources	Cost	~~175,856~~	~~175,856~~	170,451	170,451
HOL	Energy Ottawa	Facilities	Market/Cost	~~74,437~~	~~57,463~~	74,635	57,463
HOL	Energy Ottawa	IT Services	Cost	~~299,972~~	~~299,972~~	290,599	290,599
HOL	Energy Ottawa	Finance	Cost	~~190,621~~	~~190,621~~	190,621	190,621
HOL	Energy Ottawa	Communications	Cost	~~35,195~~	~~35,195~~	35,195	35,195
HOL	Energy Ottawa	Metering, Meter Data Services	Market	~~80,680~~	~~*~~	79,880	*
HOL	Energy Ottawa	Mechanic Services	Cost	~~132,954~~	~~132,954~~	134,892	134,892
Total Charged from HOL to Energy Ottawa				**~~989,715~~**	**~~892,061~~**	**976,273**	**879,221**
HOL	CDM	Human Resources	Cost	~~93,394~~	~~93,394~~	93,394	93,394
HOL	CDM	Facilities	Market/Cost	~~47,508~~	~~33,097~~	48,640	33,097
HOL	CDM	IT Services	Cost	~~156,011~~	~~156,011~~	156,013	156,013
HOL	CDM	Finance	Cost	~~111,684~~	~~111,684~~	111,684	111,684
HOL	CDM	Communications	Cost	~~25,140~~	~~25,140~~	25,140	25,140
HOL	CDM	Fleet	Cost	~~4,100~~	~~4,100~~	8,200	8,200
Total Charged from HOL to CDM				**~~437,837~~**	**~~423,426~~**	**443,071**	**427,528**

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	~~2014 Forecast~~	~~2014 Forecast~~	2014 Actual	2014 Actual
From	To			~~% of Corporate Costs Allocated~~	~~Amount Allocated~~	% of Corporate Costs Allocated	Amount Allocated
				~~%~~	~~$~~	%	$
HOHI	HOL	Legal, Corporate Admin & Regulatory	Cost	~~50%~~	~~218,307~~	50%	170,586
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgmt	Cost	~~66%~~	~~1,510,480~~	66%	1,333,337
HOHI	HOL	Treasury	Cost	~~88%~~	~~330,000~~	88%	330,000
HOHI	HOL	HR, Safety & Environment	Cost	~~92%~~	~~567,892~~	92%	572,558
HOHI	HOL	Corporate Communications	Cost	~~20%~~	~~188,479~~	20%	126,697
HOHI	HOL	Information Management & Technology Services	Cost	~~45%~~	~~193,573~~	45%	146,916
HOHI	HOL	Management Services	Cost	~~46%~~	~~617,350~~	46%	524,753
Total Charged from HOHI to HOL					**~~3,626,081~~**		**3,204,847**
HOHI	CDM	Management Services	Cost	~~50%~~	~~173,917~~	50%	155,153
Total Charged from HOHI to CDM					**~~173,917~~**		**155,153**

Note:

1 This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2015 Bridge Year

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HOL	HOHI	Human Resources	Cost	124,792	124,792
HOL	HOHI	Facilities	Market/Cost	229,224	148,721
HOL	HOHI	IT Services	Cost	214,752	214,752
HOL	HOHI	Finance	Cost	169,500	169,500
HOL	HOHI	Communications	Cost	80,664	80,664
Total Charged from HOL to HOHI				**818,932**	**738,429**
HOL	Energy Ottawa	Human Resources	Cost	186,948	186,948
HOL	Energy Ottawa	Facilities	Market/Cost	75,299	58,834
HOL	Energy Ottawa	IT Services	Cost	329,096	329,096
HOL	Energy Ottawa	Finance	Cost	194,575	194,575
HOL	Energy Ottawa	Communications	Cost	33,216	33,216
HOL	Energy Ottawa	Metering, Meter Data Services	Market	79,920	*
HOL	Energy Ottawa	Mechanic Services	Cost	144,101	144,101
Total Charged from HOL to Energy Ottawa				**1,043,155**	**946,770**
HOL	CDM	Human Resources	Cost	94,000	94,000
HOL	CDM	Facilities	Market/Cost	49,260	34,784
HOL	CDM	IT Services	Cost	161,768	161,768
HOL	CDM	Finance	Cost	118,536	118,536
HOL	CDM	Communications	Cost	23,724	23,724
HOL	CDM	Fleet	Cost	8,376	8,376
Total Charged from HOL to CDM				**455,664**	**441,188**

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOHI	HOL	Legal, Corporate Admin & Regulatory	Cost	50%	210,793
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgmt	Cost	64%	1,439,594
HOHI	HOL	Treasury	Cost	67%	253,000
HOHI	HOL	HR, Safety & Environment	Cost	92%	577,187
HOHI	HOL	Corporate Communications	Cost	20%	185,806
HOHI	HOL	Information Management & Technology Services	Cost	45%	244,523
HOHI	HOL	Management Services	Cost	46%	615,503
HOHI	HOL	Board of Directors	Cost	27%	120,338
Total Charged from HOHI to HOL					**3,646,744**
HOHI	CDM	Management Services	Cost	50%	173,256
Total Charged from HOHI to CDM					**173,256**

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

Appendix 2-N
Shared Services and Corporate Cost Allocation

Year: 2016 Test Year

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
HOL	HOHI	Human Resources	Cost	127,304	127,304
HOL	HOHI	Facilities	Market/Cost	233,828	151,710
HOL	HOHI	IT Services	Cost	219,064	219,064
HOL	HOHI	Finance	Cost	172,908	172,908
HOL	HOHI	Communications	Cost	82,284	82,284
Total Charged from HOL to HOHI				**835,388**	**753,270**
HOL	Energy Ottawa	Human Resources	Cost	190,704	190,704
HOL	Energy Ottawa	Facilities	Market/Cost	76,811	60,017
HOL	Energy Ottawa	IT Services	Cost	335,716	335,716
HOL	Energy Ottawa	Finance	Cost	198,487	198,487
HOL	Energy Ottawa	Communications	Cost	33,888	33,888
HOL	Energy Ottawa	Metering, Meter Data Services	Market	79,800	*
HOL	Energy Ottawa	Mechanic Services	Cost	146,076	146,076
Total Charged from HOL to Energy Ottawa				**1,061,482**	**964,888**
HOL	CDM	Human Resources	Cost	95,892	95,892
HOL	CDM	Facilities	Market/Cost	50,256	35,483
HOL	CDM	IT Services	Cost	165,016	165,016
HOL	CDM	Finance	Cost	120,924	120,924
HOL	CDM	Communications	Cost	24,204	24,204
HOL	CDM	Fleet	Cost	8,544	8,544
Total Charged from HOL to CDM				**464,836**	**450,063**

* Metering, Meter Data Services costs related to Energy Ottawa are considered immaterial and not practicable to determine

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
HOHI	HOL	Legal, Corporate Admin & Regulatory	Cost	50%	215,030
HOHI	HOL	Finance, Internal Audit & Enterprise Risk Mgmt	Cost	64%	1,468,530
HOHI	HOL	Treasury	Cost	67%	258,085
HOHI	HOL	HR, Safety & Environment	Cost	92%	588,788
HOHI	HOL	Corporate Communications	Cost	20%	189,541
HOHI	HOL	Information Management & Technology Services	Cost	45%	249,438
HOHI	HOL	Management Services	Cost	46%	627,871
HOHI	HOL	Board of Directors	Cost	27%	122,757
Total Charged from HOHI to HOL					**3,720,040**
HOHI	CDM	Management Services	Cost	50%	176,736
Total Charged from HOHI to CDM					**176,736**

Note:

1 **This appendix must be completed in relation to each service provided or received for the Historical (actuals), Bridge and Test years. The required information includes:**

- ***Type of Service:***

Services such as billing, accounting, payroll, etc. The applicant must identify any costs related to the Board of Directors of the parent company that are allocated to the applicant.

- ***Pricing Methodology:***

Pricing Methodology includes approaches such as cost-base, market-base, tendering, etc. The applicant must provide evidence demonstrating the pricing methodology used. The applicant must also provide a description of why that pricing methodology was chosen, whether or not it is in conformity with ARC, and why it is appropriate.

- ***% Allocation:***

The applicant must provide the percentage of the costs allocated to the entity for the service being offered. The Applicant must also provide a description of the allocator and why it is an appropriate allocator.

REGULATORY COSTS

1.0 INTRODUCTION

Regulatory costs for Hydro Ottawa Limited ("Hydro Ottawa") are included in the Uniform System of Accounts ("USoA") 5655, 5630 and 5620 – a summary of Regulatory Expenses are shown in Table 1. Please refer to Appendix 2-M - Regulatory Cost Schedule for further details. This includes Ontario Energy Board (the "Board") cost assessments and licence fees, Electrical Safety Authority ("ESA") cost assessments, intervenor and other cost awards, professional services (legal and consulting) and costs to publish public notices, all of which are considered on-going costs. Annual assessment fees paid to the Board is the largest expenditure in this category. Hydro Ottawa has seen increases in total Regulatory Costs, the budget for the test year, 2016 is $1.4M. The volume of proceedings at the Board continues to increase, resulting in higher annual cost awards. Furthermore, the continual changes within the electricity industry, including aging infrastructure and an aging workforce as well as a number of issues specific to Hydro Ottawa means that this application is for the 2016 test year only and is not considered a base year for a subsequent IRM process.

Hydro Ottawa's costs of regulatory staff have not been included in USoA Accounts 5655, 5630 or 5620. These costs are contained within the general OM&A budgets. Personnel from other departments who work on the preparation of the rate case (such as finance, distribution asset management, treasury, human resources, customer service, information technology, etc.) are not included in Accounts 5655, 5630 or 5620. These costs are contained within their departmental budgets.

Table 1 – Regulatory Cost Schedule (Summary)

Last Rebasing Year (2012 Board Approved)	~~Most Current Actuals Year 2014~~	2014 Actuals	2015 Bridge Year	2016 Test Year
$1,298,157	~~$ 1,173,303~~	$1,167,250	$ 1,338,863	$ 1,365,775

File Number:	EB-2015-0004
Exhibit:	D
Tab:	2
Schedule:	4
Page:	1 OF 1
Date:	~~ORIGINAL~~ Updated: June 29,2015

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2012 Board Approved)	~~Most Current Actuals Year 2014~~	2014 Actuals	2015 Bridge Year	~~Annual % Change~~	Annual % Change	2016 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(F1)	(G)	~~(H) = [(G)-(F)]/(F)~~	(H) = [(G)-(F1)]/(F1)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 775,196	~~$ 880,729~~	$ 883,460	$ 898,344	~~2.00%~~	1.68%	$ 916,311	2.00%
2	OEB Section 30 Costs (Applicant-originated)											
3	OEB Section 30 Costs (OEB-initiated)											
4	Expert Witness costs for regulatory matters											
5	Legal costs for regulatory matters	5655		On-Going	$ 208,829	~~$ 55,955~~	$ -	$ 157,547	~~181.56%~~		$ 160,711	2.01%
6	Consultants' costs for regulatory matters	5630		On-Going	$ 20,000	~~$ 64,773~~	$ 121,056	$ 66,069	~~2.00%~~	-45.42%	$ 16,188	-75.50%
7	Operating expenses associated with staff resources allocated to regulatory matters											
8	Operating expenses associated with other resources allocated to regulatory matters [1]											
9	Other regulatory agency fees or assessments	5655		On-Going	$ 127,044	~~$ 135,374~~	$ 136,457	$ 138,081	~~2.00%~~	1.19%	$ 140,843	2.00%
10	Any other costs for regulatory matters (please define)	5655		On-Going	$ 5,208							
11	Intervenor costs	5620		On-Going	$ 161,880	~~$ 36,472~~	$ 26,277	$ 78,822	~~116.12%~~	199.96%	$ 131,722	67.11%
12	Sub-total - Ongoing Costs [3]		$ -		$ 1,298,157	~~$ 1,173,303~~	$ 1,167,250	$ 1,338,863	~~14.11%~~	14.70%	$ 1,365,775	2.01%
13	Sub-total - One-time Costs [4]		$ -		$ -	~~$ -~~	$ -	$ -			$ -	
14	Total		$ -		$ 1,298,157	~~$ 1,173,303~~	$ 1,167,250	$ 1,338,863	~~14.11%~~	14.70%	$ 1,365,775	2.01%

Please fill out the following table for all <u>one-time</u> costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2015 Bridge Year	2016 Test Year
4	Expert Witness costs			
5	Legal costs			
6	Consultants' costs			
7	Incremental operating expenses associated with staff resources allocated to this application.			
8	Incremental operating expenses associated with other resources allocated to this application. [1]			
11	Intervenor costs			

CHARITABLE AND POLITICAL DONATIONS

1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") follows the OEB's Accounting Procedures Handbook ("APH") with respect to charitable and political donations. As per the APH, Donations are tracked in the Uniform System of Accounts ("USoA") 6205 Donations and are not included in the revenue requirement for the Test Years.

Only donations specifically for the Low-Income Energy Assistance Program ("LEAP") as tracked in the USoA Sub-account 6205 Donations, sub-account LEAP Funding are included in the revenue requirement for the Test Years. The Board has prescribed the LEAP program to provide assistance to low-income consumers in paying their electricity bills. Please refer to Exhibit D-2-5 for further details on the LEAP program.

The following Table 1 summarizes charitable and political donations that are both recoverable and non-recoverable for revenue requirement from 2012 to 2016 Test Year.

Table 1– Charitable and Political Donations Summary

Category	2012 Actual	2013 Actual	~~Most Current Actuals Year 2014~~	2014 Actual	2015 Bridge Year	2016 Test Year
Rate Recoverable	$185,000	$187,000	~~$187,152~~	$187,300	$190,984	$ 210,088
Non-Rate Recoverable	$190,124	190,536	~~190,214~~	204,146	154,750	156,275
TOTAL	**$375,124**	**$377,536**	**~~$377,366~~**	**$391,446**	**$345,734**	**$ 366,363**

Hydro Ottawa will also adhere to any requirements for the recording of charitable and political donations for any new Board-Approved programs to assist low-income

customers, such as the Low-Income Strategy Review (EB-2014-0227), that are regulated by the Board.

DEPRECIATION/AMORTIZATION/DISPOSAL SCHEDULE

Hydro Ottawa Limited ("Hydro Ottawa") is not proposing to make any changes from the amortization rates that were previously accepted in the 2012 Electricity Distribution Rate Application (EB-2011-0054) therefore an amortization study is not included with this application. Hydro Ottawa's useful lives are provided in Table 4 and are consistent with the 2012 lives.

Hydro Ottawa uses the half-year rule for calculating depreciation/amortization in the year that capital additions are added to the rate base for both actual and budgeted pooled assets, except in the case of discrete material assets, such as a station. In those specific cases, that actual or forecasted in-service month would be used to calculate the depreciation/amortization.

The following tables (Table 1 and Table 2) detail the amortization expenses for 2012 Actual, 2013 Actual, 2014 ~~Forecast~~ Actual, and 2015 to 2020 Budget, by asset group. As noted in the 2012 Electricity Distribution Rate Application (EB-2011-0054), Hydro Ottawa received approval to recover the cost of meters stranded as a result of the installation of Smart Meters over a six year period; $2,987k has been included in the amortization expense for years 2012 and 2013, which are the fifth and last year period.

Also included in the Tables is the effect on amortization from disposals in 2012 and 2013 and 2014 forecast and budgeted disposals for 2015 to 2020.

Hydro Ottawa has not provided Chapter 2 MIFRS Appendices (2-CA to 2-CI) of the Board's Chapter 2 2.7.4 Depreciation, Amortization and Depletion of the Filing Requirements for Transmission and Distribution Applications as it is a simplified approach to the calculation of depreciation expense and the requested information is already provided in Chapter 2 Appendix 2 – BA.

Table 1: Amortization Expense 2012 to ~~2016~~ 2014 (In $000's)[1]

Asset Group	2012 Amortization Expense	2012 Disposal	2013 Amortization Expense	2013 Disposal	2014 Forecast Amortization Expense	2014 Actual Amortization Expense	2014 Forecast Disposal	2014 Actual Disposal
Land and Buildings	(593)	0	(721)	0	(794)	(821)	0	0
TS Primary Above 50	(2,202)	0	(2,328)	0	(2,854)	(2,812)	3	3
DS	(3,697)	0	(3,634)	644	(3,704)	(4,030)	32	35
Pole, Wires	(8,982)	28	(10,000)	182	(10,820)	(9,642)	424	438
Line Transformers	(1,973)	12	(2,241)	23	(2,305)	(1,809)	2	5
Services and Meters	(7,979)	3	(8,119)	289	(5,325)	(5,023)	6	1,951
General Plant	(1,971)	0	(1,880)	0	(1,744)	(1,806)	2	2
Equipment	(2,139)	2	(2,288)	0	(2,699)	(2,364)	33	33
IT Assets	(9,064)	0	(9,181)	0	(7,899)	(7,079)	92	92
Other Distribution Assets[1]	4	0	593	0	1,628	(537)	4	4
Total	**$ (38,595)**	**$ 44**	**$ (39,798)**	**$ 1,138**	**$ (36,517)**	**$ (35,923)**	**$ 598**	$ 2,562

[1] Original Forecast numbers reflect proposed 2016 to 2020 rates. Rates for 2016 to 2020 will be updated once the OEB releases the 2016 models.

Asset Group	2012 Amortization Expense	2012 Disposal	2013 Amortization Expense	2013 Disposal	2014 Amortization Expense	2014 Disposal	2015 Amortization Expense	2015 Disposal	2016 Amortization Expense	2016 Disposal
Land and Buildings	(593)	0	(721)	0	(794)	0	(858)	0	(891)	0
TS Primary Above 50	(2,202)	0	(2,328)	0	(2,854)	3	(3,144)	0	(3,158)	0
DS	(3,697)	0	(3,634)	644	(3,704)	32	(3,566)	92	(3,364)	92
Poles, Wires	(8,982)	28	(10,000)	182	(10,820)	424	(13,615)	714	(15,002)	714
Line Transformers	(1,973)	12	(2,241)	23	(2,305)	2	(3,608)	118	(3,993)	118
Services and Meters	(7,979)	3	(8,119)	289	(5,325)	6	(6,595)	52	(6,918)	52
General Plant	(1,971)	0	(1,880)	0	(1,744)	2	(1,821)	0	(1,855)	0
Equipment	(2,139)	2	(2,288)	0	(2,699)	33	(2,528)	38	(2,669)	38
IT Assets	(9,064)	0	(9,181)	0	(7,899)	92	(8,317)	0	(9,071)	0
Capital Contributions Paid	0	0	0	0	0	0	0	0	0	0
Other Distribution Assets [1]	4	0	593	0	1,628	4	5,494	0	6,093	0
Total	**$ (38,595)**	**$ 44**	**$ (39,798)**	**$ 1,138**	**$ (36,517)**	**$ 598**	**$ (38,558)**	**$ 1,013**	**$ (40,826)**	**$ 1,013**

Note 1: Other Distribution Assets include Deferred Revenue

Table 2: Amortization Expense ~~2017~~ 2015 to ~~2020~~ 2017 (In $000's)[2]

Asset Group	2015 Original Amortization Expense	2015 Amortization Expense	2015 Disposal	2016 Original Amortization Expense	2016 Amortization Expense	2016 Disposal	2017 Original Amortization Expense	2017 Amortization Expense	2017 Disposal
Land and Buildings	**(858)**	(858)	0	(891)	(891)	0	(905)	(905)	0
TS Primary Above 50	**(3,144)**	(3,119)	0	(3,158)	(3,132)	0	(3,176)	(3,150)	0
DS	**(3,566)**	(3,526)	92	(3,364)	(3,323)	92	(3,427)	(3,386)	92
Pole, Wires	**(13,615)**	(10,624)	714	(15,002)	(12,011)	714	(16,282)	(13,291)	714
Line Transformers	**(3,608)**	(2,210)	118	(3,993)	(2,595)	118	(4,340)	(2,942)	118
Services and Meters	**(6,595)**	(5,528)	52	(6,918)	(5,817)	52	(7,244)	(6,127)	52
General Plant	**(1,821)**	(1,821)	0	(1,855)	(1,855)	0	(1,832)	(1,832)	0
Equipment	**(2,528)**	(2,245)	38	(2,669)	(2,386)	38	(2,819)	(2,536)	38
IT Assets	**(8,317)**	(8,212)	0	(9,071)	(9,071)	0	(10,805)	(10,805)	0
Other Distribution Assets[1]	**5,494**	(274)	0	6,093	325	0	6,684	917	0
Total	**$ (38,558)**	**$ (38,416)**	**$ 1,013**	**$ (40,826)**	**$ (40,756)**	**$ 1,013**	**$ (44,145)**	**$ (44,058)**	**$ 1,013**

Note 1: Other Distribution Assets include Deferred Revenue

[2] Original Forecast numbers reflect proposed 2016 to 2020 rates. Rates for 2016 to 2020 will be updated once the OEB releases the 2016 models.

Asset Group	2017 Amortization Expense	2017 Disposal	2018 Amortization Expense	2018 Disposal	2019 Amortization Expense	2019 Disposal	2020 Amortization Expense	2020 Disposal
Land and Buildings	(905)	0	(940)	0	(976)	0	(1,017)	0
TS Primary Above 50	(3,176)	0	(3,249)	0	(3,277)	0	(3,261)	0
DS	(3,427)	92	(3,804)	92	(4,112)	92	(4,283)	92
Poles, Wires	(16,282)	714	(17,610)	714	(18,872)	714	(20,119)	714
Line Transformers	(4,340)	118	(4,715)	118	(5,093)	118	(5,481)	118
Services and Meters	(7,244)	52	(7,621)	52	(7,977)	52	(8,360)	52
General Plant	(1,832)	0	(1,762)	0	(1,715)	0	(1,721)	0
Equipment	(2,819)	38	(3,115)	38	(3,284)	38	(3,385)	38
IT Assets	(10,805)	0	(11,430)	0	(11,332)	0	(10,986)	0
Capital Contributions Paid	0	0	0	0	0	0	0	0
Other Distribution Assets [1]	6,684	0	7,200	0	7,689	0	8,319	0
Total	**$ (44,145)**	**$ 1,013**	**$ (47,047)**	**$ 1,013**	**$ (48,949)**	**$ 1,013**	**$ (50,295)**	**$ 1,013**

Table 3: Amortization Expense 2018 to 2020 (In $000's)[3]

Asset Group	2018 Original Amortization Expense	2018 Amortization Expense	2018 Disposal	2019 Original Amortization Expense	2019 Amortization Expense	2019 Disposal	2020 Original Amortization Expense	2020 Amortization Expense	2020 Disposal
Land and Buildings	(940)	(940)	0	(976)	(976)	0	(1,017)	(1,017)	0
TS Primary Above 50	(3,249)	(3,224)	0	(3,277)	(3,251)	0	(3,261)	(3,235)	0
DS	(3,804)	(3,764)	92	(4,112)	(4,072)	92	(4,283)	(4,243)	92
Pole, Wires	(17,610)	(14,619)	714	(18,872)	(15,881)	714	(20,119)	(17,128)	714
Line Transformers	(4,715)	(3,317)	118	(5,093)	(3,696)	118	(5,481)	(4,084)	118
Services and Meters	(7,621)	(6,487)	52	(7,977)	(6,822)	52	(8,360)	(7,196)	52
General Plant	(1,762)	(1,762)	0	(1,715)	(1,715)	0	(1,721)	(1,721)	0
Equipment	(3,115)	(2,832)	38	(3,284)	(3,001)	38	(3,385)	(3,102)	38
IT Assets	(11,430)	(11,430)	0	(11,332)	(11,332)	0	(10,986)	(10,986)	0
Other Distribution Assets[1]	7,200	1,432	0	7,689	1,921	0	8,319	2,551	0
Total	**$ (47,047)**	**$ (46,943)**	**$ 1,013**	**$ (48,949)**	**$ (48,824)**	**$ 1,013**	**$ (50,295)**	**$ (50,161)**	**$ 1,013**

Note 1: Other Distribution Assets include Deferred Revenue

[3] Original Forecast numbers reflect proposed 2016 to 2020 rates. Rates for 2016 to 2020 will be updated once the OEB releases the 2016 models.

Table ~~3~~ 4: Asset Retirement Obligations ("ARO")

Asset Retirement Obligation	USofA	Net Book Value 2012	2013 Amortization Expense	Net Book Value 2013
Station Equipment (Below 50kV)	1820	$2,410	($2,410)	0
Line Transformers	1815	$232,294	($232,294)	0
Total		**$234,704**	**($234,704)**	**0**

Table ~~4~~ 5 – Useful Lives

USofA Account Number	Description	Useful life (years)
1805	Land	NA
1806	Land Rights	50
1808	Buildings and Fixtures	30 - 75
1815	Station Equipment (Above 50kV)	15 - 45
1820	Station Equipment (Below 50kV)	15 - 45
1830	Poles, Towers, Fixtures	45
1835	Overhead Conductors and Devices	25 - 45
1840	Underground Conduit	40
1845	Underground Conductors and Devices	25 - 60
1850	Line Transformers	35
1855	Services	45
1860	Meters	15 – 25
1860	Smart Meters	15
1905	Land	NA
1612 (formerly 1906)	Land Rights	50
1908	Buildings and Fixtures	20 - 75
1915	Office Furniture & Equipment	10
1920	Computer Equipment – Hardware	5
1611 (formerly 1925)	Computer Software	5 -10
1930	Automobiles	7
1930	Trucks Less Than 3 tonnes	8
1930	Trucks Greater Than 3 tonnes	12
1930	Powered Equip & Trailers	15
1935	Stores Equipment	10
1940	Tools, Shop & Garage Equipment	10
1945	Measurement & Testing Equipment	10
1955	Communication Equipment	8
1960	Equipment - Miscellaneous	10
1970	Load Mgmt Contrls Cust Prem	10
1975	Load Mgmt Contrls Utility Prem	10
1980	System Supervisory Equipment	15

LOSS ADJUSTMENT FACTORS

1.0 DISTRIBUTION LOSSES

Table 1 below provides losses as a percentage of purchases for the previous ~~five~~ six years. Hydro Ottawa Limited's ("Hydro Ottawa") losses have not been greater than 5% in the past five years. Hydro Ottawa contains no distributors embedded in its area and is not an embedded distributor itself; however it does have a number of delivery points embedded in Hydro One Network Inc.'s service territory.

Table 1 – Losses as a % of Purchases for Previous ~~Five~~ Six Years

	2009	2010	2011	2012	2013	2014
Electricity Purchases (MWh)	7,784,723	7,839,865	7,853,159	7,856,204	7,722,152	7,636,154
Electricity Sales (MWh)	7,560,847	7,594,977	7,607,711	7,570,226	7,519,454	7,425,541
Losses (MWh)	223,876	244,888	245,447	285,978	202,698	210,614
Losses %	2.88%	3.12%	3.13%	3.64%	2.62%	2.76%

2.0 LOSS ADJUSTMENT FACTORS

Hydro Ottawa's current loss adjustment factors, which have been approved by the Ontario Energy Board (the "Board") as part of the EB-2011-0054 Decision, are shown below:

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0358
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0170
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0254
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0069

Hydro Ottawa has completed Appendix 2-R (Updated) of the Board's Update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, July 18, 2014, which is also attached as a PDF to this Exhibit.

As a result of the updated calculation in Appendix 2-R (Updated), Hydro Ottawa is requesting approval of the following revised loss factors based on the 5 year average (ending 2013), for Secondary and Primary Metered Customers:

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0338
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0163
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0234
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0062

Hydro Ottawa will update rates and its loss factors to reflect the new 5 year average (ending 2014) using the Board's 2016 models. The company expects these models to be release by the end of July 2015.

File Number:	EB-2015-0004
Exhibit:	H
Tab:	9
Schedule:	1
Page:	1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-R
Loss Factors

		Historical Years						5-Year Average (ending 2013)	5-Year Average (ending 2014)
		2009	2010	2011	2012	2013	2014		
	Losses Within Distributor's System								
A(1)	"Wholesale" kWh delivered to distributor (higher value)	7,784,723,200	7,839,865,242	7,853,158,848	7,856,203,955	7,722,151,641	7,636,154,336	7,811,220,577	7,781,506,804
A(2)	"Wholesale" kWh delivered to distributor (lower value)	7,739,120,106	7,793,416,883	7,806,353,006	7,808,192,459	7,675,507,526	7,588,912,393	7,764,517,996	7,734,476,453
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	637,811,922	689,846,705	666,105,214	650,508,627	617,344,861	611,101,307	652,323,466	646,981,343
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	7,101,308,184	7,103,570,178	7,140,247,792	7,157,683,832	7,058,162,665	6,977,811,086	7,112,194,530	7,087,495,110
D	"Retail" kWh delivered by distributor	7,560,846,876	7,594,977,085	7,607,711,356	7,570,226,415	7,519,454,130	7,425,540,554	7,570,643,172	7,543,581,908
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	633,982,714	685,666,594	662,045,474	646,432,433	613,513,830	607,320,659	648,328,209	642,995,798
F	Net "Retail" kWh delivered by distributor = **D - E**	6,926,864,162	6,909,310,491	6,945,665,882	6,923,793,982	6,905,940,300	6,818,219,896	6,922,314,963	6,900,586,110
G	Loss Factor in Distributor's system = **C / F**	1.0252	1.0281	1.0280	1.0338	1.0220	1.0234	1.0274	1.0271
	Losses Upstream of Distributor's System								
H	Supply Facilities Loss Factor	1.0060	1.0061	1.0061	1.0063	1.0062	1.0062	1.0062	1.0062
	Total Losses								
I	Total Loss Factor = **G x H**	1.0314	1.0344	1.0343	1.0403	1.0284	1.0298	1.0338	1.0335

Notes

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the higher of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the higher of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the lower of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).

D kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.

G and **I** These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.

H If directly connected to the IESO-controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor's system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be calculated as the weighted average of above.

Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal including supporting calculations and any other relevant material.

CURRENT DEFERRAL AND VARIANCE ACCOUNTS

1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") has included a request for approval of the disposition for the Group 1 and Group 2 Deferral and Variance Accounts ("DVAs") based on the balances at December 31, 2013 and the forecasted interest through December 31, 2014 in this Custom Incentive Rate Application. Hydro Ottawa intends to file an updated request based on December 31, 2014 balances and forecasted interest for 2015 as part of the rate application process.

2.0 DETAILS OF DEFERRAL AND VARIANCE ACCOUNTS

Included in the following Tables 1 and 2 is a complete list of Hydro Ottawa's active DVAs categorized based on the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative ("EDDVAR Report"), which categorizes the DVA accounts into Group 1 and Group 2 accounts.

Table 1 – Group 1 Deferral and Variance Accounts

Group 1 Account – Description	Account
Low Voltage ("LV") Account	1550
Smart Meter Entity Charge Variance Account	1551
Retail Settlement Variance Account ("RSVA")- Wholesale Market Service Charge	1580
RSVA - Retail Transmission Network Charge	1584
RSVA - Retail Transmission Connection Charge	1586
RSVA - Power (Excluding Global Adjustment)	1588
RSVA - Global Adjustment	1589
Disposition and Recovery/Refund of Regulatory Balances Account	1595

Table 2 – Group 2 Deferral and Variance Accounts

Group 2 Account – Description	Account
Other Regulatory Assets	1508
Retail Cost Variance Account – Retail	1518
Renewable Connection OM&A Deferral Account	1532
Smart Grid OM&A Deferral Account	1535
Retail Cost Variance Account – STR	1548
Smart Meter Capital Account	1555
Smart Meter OM&A Account	1556
LRAM Variance Account ("LRAMVA")	1568
IFRS-CGAAP Transitional PP&E Amounts	1575
RSVA - One-time Wholesale Market Service	1582
PILs and Tax Variance	1592

Hydro Ottawa confirms that no deferral and variance accounts are being used differently than as prescribed in the Accounting Procedures Handbook ("APH").

3.0 CONTINUITY SCHEDULE

Attachment I-8(A) to this Exhibit is a complete continuity schedule for all Deferral and Variance accounts based on the Deferral and Variance Account (Continuity Schedule) Work Form – version 2.4 Excel spreadsheet as posted by the Board on its website June 26, 2014.

Hydro Ottawa is proposing to dispose of Group 1 and Group 2 accounts, except for those listed in section 3 of Exhibit I-8-1, the total DVA disposal of $8.2 million is to be returned to customers over a period of one year. This will be divided into three rate riders, the total proposed disposition for Group 1 and Group 2, excluding Global Adjustment and LRAMVA is a credit of $6.3 million to be returned to all customer classes. The global adjustment rate rider proposed would return $1.3 million to non-Regulated Price Plan ("non-RPP") customers. The LRAM rate rider proposed would return $679k to all customer classes. Please refer to Exhibit I-8-1 for further details on the disposition plan.

4.0 CARRYING CHARGES

The interest rate used for the calculation of all carrying charges was as prescribed by the Board and published quarterly on its website. Please refer to Table 3 for a listing of these interest rates up to 2015 Q3. ~~Q2.~~ Hydro Ottawa confirms it uses these interest rates as provided by the Board.

Table 3 – Interest Rates for Carrying Charges on Deferral and Variance Accounts

Approved Deferral and Variance Accounts	
Quarter by Year	**Prescribed Interest Rate**
Q3 2015	1.10%
Q2 2015	1.10%
Q1 2015	1.47%
Q4 2014	1.47%
Q3 2014	1.47%
Q2 2014	1.47%
Q1 2014	1.47%
Q4 2013	1.47%
Q3 2013	1.47%
Q2 2013	1.47%
Q1 2013	1.47%
Q4 2012	1.47%
Q3 2012	1.47%
Q2 2012	1.47%
Q1 2012	1.47%
Q4 2011	1.47%
Q3 2011	1.47%
Q2 2011	1.47%
Q1 2011	1.47%
Q4 2010	1.20%
Q3 2010	0.89%
Q2 2010	0.55%
Q1 2010	0.55%

Carrying charges were calculated on all deferral and variance accounts with the exception of:

- USofA's 1575 – IFRS –CGAAP Transitional PP&E Amounts
- USofA 1508, Other Regulatory Assets, Sub-Account P&OPEB Deferral Account and,
- 1592 - PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT.

5.0 RECONCILIATION OF CONTINUITY SCHEDULE VS. RRR's

As per the Continuity Schedule in Appendix I-8(A), there are two differences in the account balances as of December 31, 2013 between the continuity schedule and 2.1.7 Electricity Reporting and Record-keeping Requirements ("RRR's") reported to the Board.

The Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") – USofA 1568 has a difference of $104k when compared to the December 31, 2013 2.1.7 RRR as reported to the OEB. The Continuity Schedule includes balances to the end of 2014 so they can be disposed of as part of this rate application, resulting in a timing difference.

There is also a difference in USofA 1592 - PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs). Question 1 from the Board's APH FAQ's dated December 23, 2010, stated that for regulatory reporting purposes the sub-account and contra account for HST/OVAT will have a reporting amount for RRR's that nets to zero. This is consistent with Hydro Ottawa's RRR 2.1.7 filing. The same document from the Board states that the balance in this sub-account should be reported for disposition; therefore, the credit balance of $545k will be returned to customers.

The result is a variance between the RRR filing and the balance to be disposed of $441k.

6.0 STATUS OF GROUP 2 ACCOUNTS

Hydro Ottawa identified active Group 2 accounts in Table 2 of this Exhibit. Please refer to Table 4 for an outline of Group 2 accounts that Hydro Ottawa is proposing to continue or discontinue.

Table 4 - Status of Group 2 Accounts

Group 2 Account - Description	Account	Continue/Discontinue
Other Regulatory Assets	1508	Continue
Retail Cost Variance Account – Retail	1518	Continue[1]
Renewable Connection OM&A Deferral Account	1532	Continue
Smart Grid OM&A Deferral Account	1535	Continue
Retail Cost Variance Account – STR	1548	Continue[1]
Smart Meter Capital Account	1555	Discontinue[2]
Smart Meter OM&A Account	1556	Discontinue
LRAM Variance Account ("LRAMVA")	1568	Continue
IFRS-CGAAP Transitional PP&E Amounts	1575	Discontinue
RSVA - One-time Wholesale Market Service	1582	Continue
PILs and Tax Variance	1592	Discontinue

1. Proposal to Continue tracking until end of 2015, Dispose of remaining balance in 2018 for 2019 rates, see Exhibits I-7-1 and I-8-1

2. 1555 upon approval of disposition through 1595 rate rider

7.0 NEW DEFERRAL AND VARIANCE ACCOUNTS AND SUB-ACCOUNTS

Please refer to Exhibit I-1-2 for details regarding new DVAs that Hydro Ottawa is requesting.

8.0 ADJUSTMENTS TO DEFERAL AND VARIANCE ACCOUNTS

Hydro Ottawa confirms it has not made any adjustments to DVA balances that were previously approved by the board on a final basis, in either a Cost of Service or Incentive Regulation Mechanism ("IRM") proceedings.

9.0 ENERGY SALES AND COST OF POWER EXPENSE BALANCES

The sale of energy and cost of power are flow through items. The components of energy sales and the cost of power are broken down by USofA in Table 5. Hydro Ottawa does not report any difference for financial purposes between the energy sales and the cost of power. As a result, Hydro Ottawa does not derive any economic gain or loss in the flow through of these accounts.

Table 5 – Cost of Power and Energy Sales

ENERGY SALES			
Account and Description	**2012**	**2013**	**2014**
4006 Residential Energy Sales	($178,314,106)	($192,253,659)	($210,279,593)
4020 Energy Sales to Large Users	(38,006,458)	(47,291,162)	(47,781,445)
4025 Street Lighting Energy Sales	(934,382)	(2,907,587)	(3,961,458)
4030 Sentinel Lighting Energy Sales	(8,926)	(8,727)	(9,103)
4035 General Energy Sales	(370,884,811)	(401,258,444)	(416,030,058)
4050 Revenue Adjustment	1,123,181	-	9,545,695
4062 Billed WMS	(40,131,924)	(39,786,424)	(42,097,773)
4066 Billed NW	(49,877,881)	(51,001,142)	(52,741,108)
4068 Billed CN	(32,396,995)	(31,148,466)	(32,588,094)
4075 Billed - LV	(502,730)	(438,498)	(430,498)
4076 Billed Smart Metering Entity Charge		(1,984,655)	(2,898,541)
Sum of Energy Sales	**($709,935,032)**	**($768,078,763)**	**($799,271,975)**
COST OF POWER			
Account and Description	**2012**	**2013**	**2014**
4705 Power Purchased	$ 622,335,248	$ 643,719,579	$ 668,515,961
4708 Charges-WMS	37,219,173	39,786,424	42,097,773
4714 Charges-NW	49,877,881	51,001,142	52,741,108
4716 Charges-CN		31,148,466	32,588,094
4750 Charges - LV	502,730	438,498	430,498
4751 Charges - Smart Metering Charge		1,984,655	2,898,541
Sum of Cost of Power	**$ 709,935,032**	**$ 768,078,763**	**$ 799,271,975**
Sum of Energy Sales and Cost of Power	**-**	**-**	**-**

The totals of energy sales and cost of power are reconciled to the audited financial statements, please refer to Table 6.

Table 6 – Reconciliation to Audited Financial Statements

Reconciliation to Audited Financial Statements - $000's			
Energy Sales	2012	2013	2014
Total Energy Sales as per Audited Financial Statements - MIFRS	($709,935)	($768,079)	($799,272)
Cost of Power			
Total Cost of Power as per Audited Financial Statements - MIFRS	$ 709,935	$ 768,079	$ 799,272
Net Energy Sales and Cost of Power	**0**	**0**	**0**

10.0 IESO GLOBAL ADJUSTMENT CHARGE (RPP AND NON-RPP)

Hydro Ottawa confirms that the Independent Electricity System Operator ("IESO") Global Adjustment Charge is pro-rated between Regulated Price Plan ("RPP") and non-RPP portions.

ONE-TIME INCREMENTAL IFRS COSTS

1.0 INTRODUCTION

Hydro Ottawa Limited ("Hydro Ottawa") adopted International Financial Reporting Standards ("IFRS") effective January 1, 2015 for financial reporting purposes. The first day of the comparative year is referred to as the "transition date" and the first day of the year in which the utility has chosen to adopt IFRS for financial reporting purposes is referred to as the "changeover date". For Hydro Ottawa, the transition date was January 1, 2014, and the changeover date was January 1, 2015.

2.0 BACKGROUND

On February 13, 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that publicly accountable enterprises ("PAEs") would be required to transition to IFRS effective January 1, 2011. While Hydro Ottawa is not a PAE, it is a Government Business Enterprise, given its status as a municipally owned utility, and such enterprises are required to follow the same basis of accounting as PAEs.

On the original transition date IFRS did not contain a standard governing rate-regulated activities ("RRA"). Due to the significance of this issue in Canada, the Canadian AcSB postponed the original IFRS transition date to January 1, 2015 for qualifying entities with RRA, pending the completion of an interim standard by the International Accounting Standards Board ("IASB"). Until January 1, 2015, qualifying entities were permitted to continue reporting under Part V of the *Chartered Professional Accountants Canada Handbook* for publicly accountable entities ("CGAAP").

While early adoption was permitted by the Canadian AcSB, Hydro Ottawa elected to defer the adoption of IFRS for financial reporting purposes due to the continued uncertainty around the timing, scope and eventual adoption of a rate-regulated

accounting standard under IFRS, and its potential material impact on Hydro Ottawa's financial statements.

In a letter issued March 15, 2011, the Ontario Energy Board (the "Board") directed electricity distributors filing cost of service applications for rates for 2012 to make all reasonable efforts to provide the forecasts for the 2012 test year in modified IFRS ("MIFRS") accounting format.

In compliance with the Board's direction, Hydro Ottawa filed its 2012 Cost of Service Application on June 17, 2011 using MIFRS as the accounting basis.

Hydro Ottawa adopted MIFRS for regulatory accounting and reporting purposes effective January 1, 2012 with a transition date of January 1, 2011.

3.0 ADOPTION OF IFRS FOR FINANCIAL REPORTING

On January 30, 2014, the IASB issued interim standard *IFRS 14 - Regulatory Deferred Accounts* ("IFRS 14") which permits rate-regulated entities that have not yet transitioned to IFRS to use its existing RRA practices. This standard is effective January 1, 2016 with early adoption permitted. Hydro Ottawa adopted IFRS and early adopted IFRS 14 on January 1, 2015 with a transition date of January 1, 2014 for financial reporting purposes.

Hydro Ottawa continues to report under MIFRS to the Board while providing reconciliation to its audited financial statements, prepared in accordance with Part V of the *Chartered Professional Accountants Canada Handbook* for publicly accountable entities ("CGAAP"). To limit the differences caused by the different accounting basis, Hydro Ottawa has sought to align its CGAAP accounting policies with IFRS requirements wherever possible as of January 1, 2012. Nonetheless, a difference in the effective implementation dates gave rise to a $ 502k difference in the carrying values of certain Property, Plant and Equipment for CGAAP and MIFRS reporting purposes.

Consequently, Hydro Ottawa recorded a one-time adjustment to align MIFRS and CGAAP. Please see Exhibit A-4-7 Accounting Standards for further details.

4.0 ALIGNING REGULATORY REPORTING AND FINANCIAL REPORTING

Hydro Ottawa maintains two sets of records: i) a set of records using MIFRS as the accounting basis to satisfy regulatory reporting or rate-making requirements, and ii) a set of records using the applicable Canadian accounting principles (CGAAP/IFRS) to satisfy financial or statutory reporting requirements. The aligning of the regulatory and financial reporting set of records will allow Hydro Ottawa to maintain one set of records which will satisfy both reporting requirements. The consolidation of the records will serve to enhance operational efficiency and reduce the burden on Hydro Ottawa's IT systems.

With the adoption of IFRS and early adoption of IFRS 14 as the accounting basis for financial reporting purposes on January 1, 2015, Hydro Ottawa's regulatory and financial reporting records are now aligned from an accounting standards basis.

5.0 IFRS - INCREMENTAL TRANSITION COSTS ACCOUNT

The variance account is a continuation of the account established in 2009, as per the Board's guidance in the Accounting Procedures Handbook ("APH") Frequently Asked Questions ("FAQs") #3, October 2009. Hydro Ottawa confirms that no capital costs, on-going IFRS compliance costs or impacts arising from adopting accounting policy changes are recorded in the Uniform System of Account ("USofA") 1508 – Other Regulatory Assets sub-account Deferred IFRS Transition Costs Variance Account.

Hydro Ottawa confirms that all costs included meet the criteria in the APH FAQs #3, October 2009, as they are all related to professional accounting and legal fees, salaries, wages and benefits of staff as a result of one-time administrative costs caused by the transition of accounting policies, procedures and processes to IFRS. Descriptions of these costs can be found in Appendix 2-U under the column, 'Reasons why the costs

recorded meet the criteria of one-time IFRS administrative incremental costs.' Refer to Appendix 2-U for details on the costs up to December 31, 2015.

6.0 DISPOSITION REQUEST – UsofA 1508 – OTHER REGULATORY ASSETS SUB-ACCOUNT DEFERRED IFRS TRANSITION COSTS

Hydro Ottawa requests as part of this rate application, the OEB review USofA 1508– Other Regulatory Assets sub-account Deferred IFRS Transition Costs for disposition. As per Appendix 2-U Hydro Ottawa is requesting disposition of costs and carrying charges in the amount of $1,432k. This includes audited incremental transition costs to ~~2013~~ 2014, ~~unaudited~~ ~~actuals for 2014~~ and a forecast for remaining costs to be included in the bridge year, 2015. Hydro Ottawa is not forecasting any one-time administrative incremental IFRS transition costs for the test years, 2016 to 2020. Please refer to Exhibit I-8-1 for a comprehensive outline of all Hydro Ottawa's accounts proposed for disposition.

File Number:	EB-2015-0004
Exhibit:	I
Tab:	4
Schedule:	1
Page:	1
Date:	~~ORIGINAL~~ UPDATED: June 29, 2015

Appendix 2-U
One-Time Incremental IFRS Transition Costs

The following table should be completed based on the information requested below. An explanation should be provided for any blank entries. The entries should include one-time incremental IFRS transition costs that are currently included in Account 1508, Other Regulatory Assets, sub-account Deferred IFRS Transition Costs Account, or Account 1508, Other Regulatory Assets, sub-account IFRS Transition Costs Variance Account.

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Actual Costs Incurred 2012	Audited Actual Costs Incurred 2013	Audited Carrying Charges to Dec 31, 2013	~~Unaudited~~ Audited Actual Costs Incurred 2014	Forecasted Costs 2015	Total Costs Excluding Carrying Charges	Carrying Charges January 1, 2014 to December 31, 2015	Total Costs and Carrying Charges	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
professional accounting fees	$ 487,258	$ 166,626	$ 395,863	$ 84,485	$ 13,037			$ 81,000	$ 1,228,269		$ 1,228,269	IFRS consulting, advisory and comparative audit works
professional legal fees			$ 90,000						$ 90,000		$ 90,000	IFRS legal opinion
salaries, wages and benefits of staff added to support the transition to IFRS	$ 23,992	$ 261,457	$ 218,943	$ 189,811	$ 118,018		$ 110,160	$ 59,945	$ 982,326		$ 982,326	Internal project lead and temporary staff
associated staff training and development costs		$ 3,198	$ 477	$ 53	$ 2,142				$ 5,869		$ 5,869	Internal project lead and temporary staff
costs related to system upgrades, or replacements or changes where IFRS was the major reason for conversion									$ -		$ -	
									$ -		$ -	
Carrying Charges						$ 50,886			$ -	$ 37,132	$ 88,018	
									$ -		$ -	
									$ -		$ -	
Amounts, if any, included in previous Board approved rates (amounts should be negative) [3]			-$ 942,530			-$ 20,145			-$ 942,530		-$ 962,675	
									$ -		$ -	
Insert description of additional item(s) and new rows if needed.									$ -		$ -	
Total	$ 511,250	$ 431,280	-$ 237,248	$ 274,349	$ 133,197	$ 30,741	$ 110,160	$ 140,945	$ 1,363,934	$ 37,132	$ 1,431,808	

Note:

1 The Deferred IFRS Transition Costs Account and the IFRS Transition Costs Variance Account are exclusively for necessary, incremental transition costs and shall not include ongoing IFRS compliance costs or impacts arising from adopting accounting policy changes that reflect changes in the timing of the recognition of income. The incremental costs in these accounts shall not include costs related to system upgrades, or replacements or changes where IFRS was not the major reason for conversion. In addition, incremental IFRS costs shall not include capital assets or expenditures.

2 If there were any amounts approved in previous Board approved rates, please state the EB #: EB-2011-0054