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October 1, 2013

Delivered by RESS and Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
26th Floor, Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Oakville Hydro Electricity Distribution Inc.
2014 Cost of Service Distribution Rate Application
Board File No. EB-2013-0159

We are counsel to Oakville Hydro Electricity Distribution Inc. ("Oakville"), the Applicant in the above-captioned electricity distribution rate proceeding.

On December 11, 2012, the Board issued a letter to all licensed electricity distributors in which it identified the distributors that are expected to file a rebasing application in respect of their 2014 rates. Oakville Hydro was one of the distributors on that list.

Pursuant to the Board's letter, please find accompanying this letter two paper copies of Oakville Hydro's Application for Electricity Distribution Rates and Charges effective May 1, 2014. Electronic versions of the Application and associated live Excel models are being uploaded to the Board through the RESS portal.

We ask that copies of all correspondence and orders pertaining to this proceeding be delivered to the following:

Mary Caputi
Director, Regulatory Affairs
Oakville Hydro Electricity Distribution Inc.
861 Redwood Square
Oakville, ON L6K 0C7

Tel: (905) 825-6373
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and to:

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and to:

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Confidentiality

Oakville Hydro has made certain redactions in the Application, and is requesting that the Board allow the redacted information to remain in confidence in this proceeding. As discussed below, Oakville Hydro submits that the redacted information constitutes personal information, as that term is defined in the *Freedom of Information and Protection of Privacy Act* ("FIPPA"), and accordingly, it should not be disclosed to any parties to this proceeding, in accordance with Rule 9A.02 of the Board's *Rules of Practice and Procedure* and Section 4.3 of the Board's *Practice Direction on Confidential Filings*.

The redactions are from 2010, 2011 and 2012 corporate tax returns and 2010 and 2011 SR&ED expenditures claims filed as appendices to Exhibit 4 of the Application. The redacted information consists of the names of co-op students who were the subject of apprenticeship tax credit claims; the names and contract/training agreement numbers of apprentices who were the subject of apprenticeship tax credit claims; and the names and years of experience of managers involved in SR&ED projects.

The redactions have been made in the following areas of those documents:

2010

a) 2010 T2 Corporation Income Tax Return
   - Ontario Co-Operative Education Tax Credit, Part 4, area 410
   - Ontario Apprenticeship Training Tax, Part 4, area 410
   - Calculation of the Ontario Apprenticeship training tax – Part 4D, area 420

b) SR&ED Expenditures Claim 2010
   - General Information - Part 1, Section D, area 260
   - Project Information - Part 2, Section D, area 260
   - Section D – Additional project information, area 261

2011

a) 2011 SR&ED Expenditures Claim – Amended
   - Project Information (continued) - Part 2, Section D, area 254 and 260 and 261
   - Calculation of the Ontario Co-Operative Education Tax Credit – Part 4C, area 410
   - Calculation of the Ontario Apprenticeship training tax – Part 4C, area 410, and 4D, area 420
   - Apprenticeship job creation – Part 21, area 601

b) 2011 T2 Corporation Income Tax
   - Calculation of the Ontario Co-Operative Education Tax Credit – Part 4C, area 410
   - Calculation of the Ontario Apprenticeship training tax – Part 4C, area 410, and 4D, area 420

2012

a) Oakville Hydro Electricity Distribution T2 – 12312012 Draft
   - Apprenticeship job creation – Part 21, area 601
   - Calculation of the Ontario Co-Operative Education Tax Credit – Part 4C, area 410
   - Calculation of the Ontario Apprenticeship training tax – Part 4C, area 410, and 4D, area 420

To be clear, Oakville Hydro has not redacted any monetary values in the forms, and Oakville Hydro respectfully submits that the redacted material is not relevant to this proceeding in any event. Oakville Hydro has redacted only personal information relating to identifiable individuals. The information falls within the definition of "personal information" contained in Section 2 of FIPPA. Specifically, the information is recorded information about identifiable individuals including information relating to the education and employment history of the individuals; identifying numbers assigned to the individuals; and the individuals' names, which appear with other personal information relating to the individuals. As noted above, the information should not be disclosed to any parties to this proceeding.

Oakville Hydro will be filing confidential unredacted versions of the documents in accordance with Rule 9A.01.

Documents marked as confidential that are being placed on the public record

Oakville Hydro also notes that certain reports that are included in the Application have been provided to Oakville Hydro in confidence by their authors, and they contain language confirming this. Oakville Hydro has contacted the authors and received their confirmation that their reports may be placed on the public record in this proceeding. To avoid any confusion, Oakville Hydro has included cover sheets for these reports confirming that their authors have approved their placement on the public record.

Should you have any questions or require further information in respect of this matter, please do not hesitate to contact me.

Yours very truly,

BORDEN LADNER GERVAIS LLP
Per:

Original signed by James C. Sidlofsky

James C. Sidlofsky
Encls.

TOR01: 5345120: v2

EB-2013-0159

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c.15, Schedule B, as amended;

AND IN THE MATTER OF an Application by Oakville Hydro Electricity Distribution Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2014.

Title of Proceeding: An Application by Oakville Hydro Electricity Distribution Inc. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2014.

Applicants Name: Oakville Hydro Electricity Distribution Inc.

Applicant's Address for Service:

PO Box 1900
861 Redwood Square
Oakville, Ontario
L6K 0C7
Attention: Jim Collins, Chief Financial Officer
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Fax: 905-825-4437
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Applicant's Counsel and Consultant:

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Bruce Bacon, Senior Utility Rate Consultant
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Certification of Evidence

As Chief Executive Officer of Oakville Hydro Electricity Distribution Inc., I certify that, to the best of my knowledge, the evidence filed in this Application is accurate and that it is consistent with Chapter Two of the Ontario Energy Board's Filing Requirements for Transmission and Distribution Applications issued on July 17, 2013 and Chapter Five of the Ontario Energy Board's Filing Requirements for Transmission and Distribution Applications issued on March 28, 2013.

Robert W. Lister
President and Chief Executive Officer

Exhibit	Tab	Schedule	Appendix	Contents
2 – Rate Base				
	1			**Overview**
		1		Rate Base Overview
		2		Variance Analysis of Rate Base
		3		Appendix 2-BA1 Continuity Statements
	2			**Gross Assets – Property, Plant and Equipment Accumulated Amortization**
		1		Breakdown by Function
		2		Detailed Breakdown by Major Plant Account
		3		Summary of Incremental Capital Module Adjustment
		4		Reconciliation of Continuity Statements
		5		Variance Analysis on Gross Assets
	3			**Allowance for Working Capital**
		1		Overview and Calculation by Account
	4	1		**Treatment of Stranded Meters Related to Smart Meter Deployment**

1

Appendix

Administrative Documents

Executive Summary

About Oakville Hydro Electricity Distribution Inc.

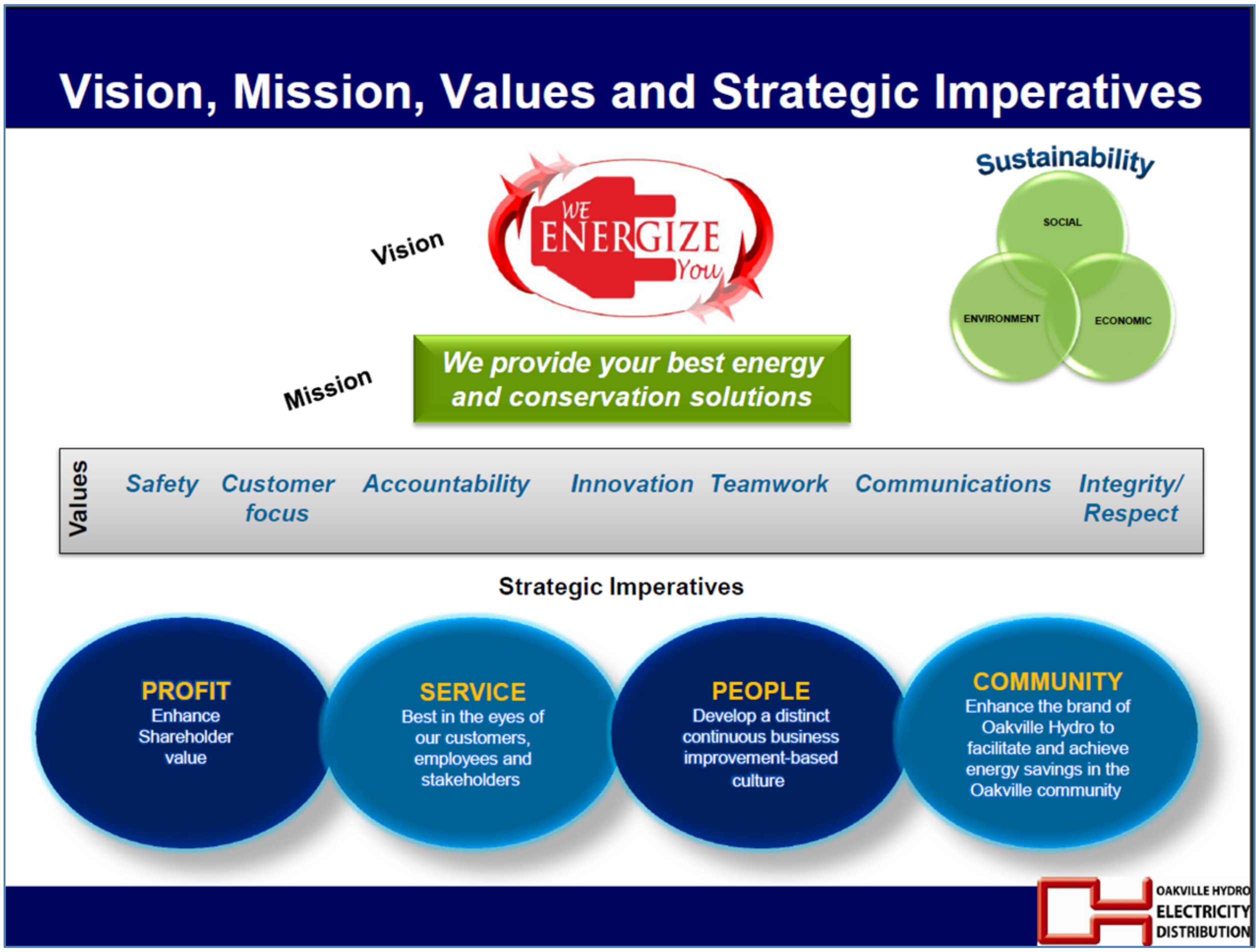
Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") is a corporation incorporated pursuant to the *Ontario Business Corporations Act*, with its head office in the Town of Oakville, Ontario. Oakville Hydro is governed by a nine member Board of Directors whose mandate is overseeing the management of the corporation's business and affairs, including: strategic planning, risk identification and risk management, succession planning, communications policies and integration of the internal control and management information systems. The members of the Board of Directors are selected to provide a balance of relevant knowledge including: business (finance, legal, accounting, marketing), public policy and government relations, board operations, electricity services, risk management, labour relations, environmental issues and occupational health and safety. The Directors are very active and engaged in the governance role for Oakville Hydro. Oakville Hydro's Mission Statement is directed towards serving customers:

Mission: *We provide your best energy and conservation solutions*

Oakville Hydro's strong governance is focused on a balanced scorecard approach. In 2011, this balanced scorecard was adopted into Oakville Hydro's strategic planning and internal corporate performance evaluation methodology.

The balanced scorecard partially aligns to the four performance outcomes established by the Ontario Energy Board (the "OEB" or the "Board") in its report on the *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (the "RRFE Report")* and its draft Regulatory Performance Scorecard. Oakville Hydro's four strategic imperatives are Profit, Service, People and Community.

Oakville Hydro's Vision, Mission, Values and Strategic Imperatives



The Ontario Energy Board's Proposed Scorecard

Performance Outcomes	Performance Categories	Measures (new in red)	
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	Connection of New Services (DSC s7.2)	Low Voltage
			High Voltage
		Appointments: Scheduled (DSC s7.3)	
		Appointments: Met (DSC s7.4)	
		Telephone Accessibility (DSC s7.6)	
		Emergency Response (DSC s7.9)	
	Customer Engagement	May include customer surveys, focus groups, town hall meetings, etc.. Distributor is required to self-rate. Reported results may not be comparable across distributors. This measure is defined and described in **Management Discussion & Analysis**	
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives.	Safety	This measure is defined and described in **Mangement Discussion & Analysis**	
	System Reliability	System Average Interruption Duration Index - Code 2 Outages (RRR s2.1.4.2.2)	
		System Average Interruption Frequency Index - Code 2 Outages (RRR s2.1.4.2.4)	
	Overall cost performance	Efficiency ranking resulting from comparative cost analysis	
		OM&A Cost	per Customer
			per Circuit Km of Line
		Net Plant Cost	per Customer
			per Circuit Km of Line
	Asset Management	Actual network CAPEX % variance from Plan (Capital Budget vs. Actual)	
Public Policy Responsiveness Utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Government Policy Directive on Conservation & Demand Management	2014 Net Annual Peak Demand Savings Target (MW)	
		2011-2014 Net Cumulative Energy Savings Target (GWh)	
	Connection of Renewable Generation	Number of Offers to Connect Micro-Generation Facilities [<=10kW] (DSC s6.2)	
		Number of CIA Completed for Other Renewable Generation Facilities [>10 kW] (DSC s6.2)	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio	
		Leverage: Total Debt to Equity Ratio	
		Profitability: Regulatory Return on Equity	Annual Cost of Capital ROE Parameter
			Achieved

- **Profit:** ***Enhance shareholder value.*** This strategic imperative is intended to focus actions towards sustainable cost reductions while optimizing service and enhancing shareholder return. This outcome aligns with the Financial Performance and Operational Effectiveness outcomes to ensure the financial viability of the utility and efficient delivery of service to customers.

- **Service**: ***Best in the eyes of our customers, employees and stakeholders.*** This is intended to focus actions towards balancing asset management, safety, reliability and costs for the benefit of the customer. The goal is to engage Oakville Hydro's customers and enhance customer focus throughout the organization and with service partners. This aligns with the Customer Focus outcome of the Board.

- **People**: ***Develop a distinct continuous business improvement culture.*** This is intended to engage the employees who deliver the services to customers and operate the distribution system. Oakville Hydro believes that the engagement and motivation of its workforce is necessary to achieve its performance outcomes. Without an engaged and motivated workforce the delivery of efficient services becomes difficult, if not impossible to achieve. The alignment of this outcome supports the Customer Focus, Operational Effectiveness and Financial Performance outcomes.

- **Community**: ***Enhance the brand of Oakville Hydro to facilitate and achieve energy savings in the Oakville Community***. This strategic imperative is intended to build on sustainability, increase customer engagement and education and broaden Oakville Hydro's profile in the community for conservation and demand management programs. This aligns with the Customer Focus outcome and assists in the delivery of public policy under the Public Policy Responsiveness outcome.

Oakville Hydro is also introducing a Sustainability Program into its strategic direction. This multi-year initiative is being conducted to minimize incremental costs to its customers and, ultimately, improve the sustainability of services offered to the residents of Oakville.

This balanced scorecard approach to operations will continue to evolve and expand throughout the organization and is a template for internal decision making at all levels. Oakville Hydro believes that customers expect a balanced approach to the delivery of electricity and maintenance of a reliable distribution system. Oakville Hydro will continue to improve on customer engagement and communications through website enhancements, use of social media and by expanding its active engagement with customers.

Application Background

Oakville Hydro filed a 2010 Cost of Service application with the Board on August 28, 2009. Since then, Oakville Hydro has filed annual Incentive Regulation Mechanism ("IRM") applications and a stand-alone Smart Meter Prudence Application. The impact of these applications is summarized in Table 1-1 below.

Table 1-1: Impact of IRM Applications

Date of Board Approval	Board File Number	Application Type	Approved increase in Revenue Requirement
March 14, 2011	EB-2010-0104	IRM (including an Incremental Capital Claim).	$1.8M
March 22, 2012	EB-2011-0189	IRM	$0.2M
August 23, 2012	EB-2012-0193	Smart Meter Prudence Review	$2.1M
April 4, 2013	EB-2012-0154	IRM	$0.1M

Current Application (EB-2013-0159)

With the RRFE Report, the Board is applying a performance-based approach to regulation. Oakville Hydro has already adopted this format and will continue to respond to customer preferences, enhance distributor productivity and promote innovation. Oakville Hydro's 2014 Cost of Service Application supports the four outcomes established by the Board:

- ***Customer Focus:*** services are provided in a manner that responds to identified customer preferences;

- ***Operational Effectiveness*:** continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

- ***Public Policy Responsiveness*:** utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

- ***Financial Performance*:** financial viability is maintained; and savings from operational effectiveness are sustainable.

Specifically, Oakville Hydro believes this application is necessary to re-align distribution rates in order to recover its revenue deficiency of $5.4M in support of the following drivers:

- ***North Oakville (Glenorchy) Municipal Transformer Station*:** An increase in revenue requirement of $1.8 million to recover capital costs associated with the design and construction of the Glenorchy Municipal Transformer Station and earn a fair return on this investment. This station is considered necessary to deliver reliable electricity in both Oakville and Milton. The Glenorchy Municipal Transformer Station was the subject of an Incremental Capital Module ("ICM") application as part of EB-2010-0104 and was approved by the Board. As a result of the Board's approval, an ICM rate rider was established which will expire on April 30, 2014.

- ***Smart Meter implementation*:** An increase in the revenue requirement of $2.1 million to recover the capital and operating costs and earn a fair return on the assets associated with the implementation of the mandated conversion to smart meters. Smart meters were part of a public policy directive, but will facilitate improved customer service as the functionality associated with the available smart meter data evolves and improves. The recovery of costs associated with smart meters was the subject of a Smart Meter Prudence Review application (EB-2012-0193). The outcome of that application was a Board Decision that approved Smart Meter Incremental Revenue Rate Rider which will expire on April 30, 2014.

- ***Current distribution system operation and maintenance*:** An increase in the revenue requirement of $1.5 million to support the operating costs associated with the Glenorchy Municipal Transformer Station, enhanced business planning and asset management, improved customer service and billing accuracy, investments in employees to create a more engaged and higher performing workforce, investment in productivity improvement initiatives, a safer work environment for both Oakville Hydro's employees and the public, more effective and expedient responses to outages and continued financial sustainability in the medium and long term.

Key Elements of the Application

A. Revenue Requirement

Oakville Hydro is requesting the approval of its proposed service revenue requirement of $38,916,139, an increase of $5,715,831 or 17%, compared with the 2010 approved service revenue requirement as shown in Table 1-2, Service Revenue Requirement.

Table 1-2: Service Revenue Requirement

Description	2010 Board Approved ($000's)	2014 Test Year ($000's)	Increase ($000's)	Increase (%)
Reporting Basis	**Old CGAAP**	**New CGAAP**		
OM&A Expenses	$11,629	$19,215	$7,586	65.2%
Depreciation and Amortization	9,808	8,611	(1,197)	-12.2%
Return on Equity - Target	5,156	6,549	1,393	27.0%
Interest	4,410	4,337	(73)	-1.7%
Taxes Other than PILs	298	203	(95)	-31.8%
PILs	1,899	-	(1,899)	-100.0%
Service Revenue Requirement	**$33,200**	**$38,916**	**$5,716**	**17%**
Revenue Offsets	2,063	2,036	(27)	**-1%**
Base Revenue Requirement	**$31,137**	**$36,880**	**$5,743**	**18%**
Return on Equity - Target	**9.85%**	**8.98%**		

The primary customer concerns, based on customer surveys, include cost, reliability and billing accuracy. Oakville Hydro is very aware, and concerned, that the maintenance and continued modernization of its electricity distribution infrastructure will exert cost pressures on its customers but; is also aware of the need for safe and reliable delivery of electricity.

System Reliability:

Oakville Hydro has and will continue to focus on reliability and safety in order to meet customer expectations. A new position, Supervisor of Asset Management, was created to implement the Asset Management Process and continuously review, refine and improve the distribution assets through the evaluation of asset condition, capacity utilization, performance measures, and risk consequence failure analysis and balance against cost efficiency and effectiveness. Ongoing investments, including measured adoption of Smart Grid technology is necessary to maintain and improve reliability. Oakville Hydro's reliability statistics for the System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI") illustrate that Oakville Hydro's distribution system is performing reliably. Oakville Hydro is committed to making the necessary capital and operating investments, to maintain or improve the reliability of its distribution system.

Table 1 -3: Reliability Statistics for (SAIDI)

Year	SAIDI	Provincial
2008	1.21	1.14
2009	0.77	1.19
2010	0.73	0.97
2011	0.46	1.33
2012	0.81	1.08

Reliability Statistics for (SAIDI)

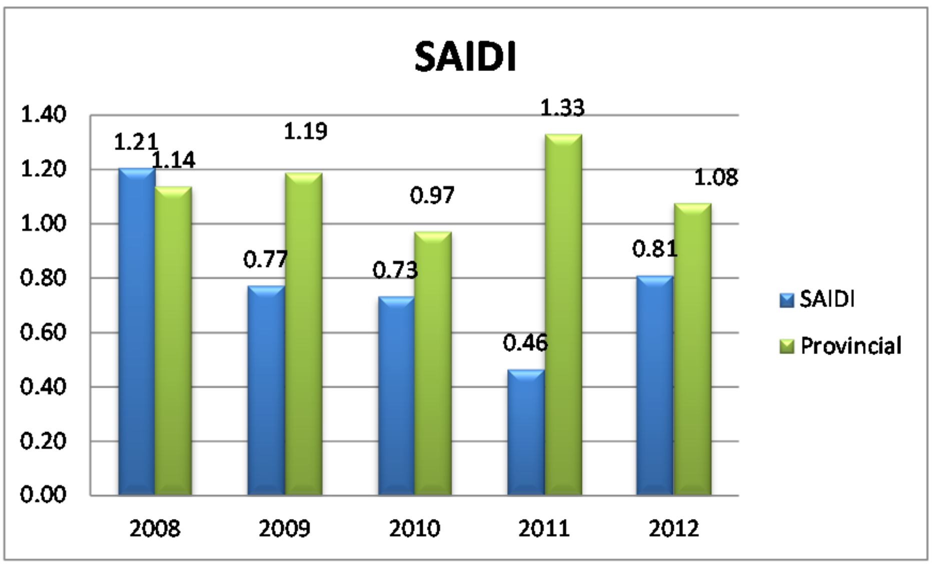


Table 1 -4: Reliability Statistics for (SAIFI)

Year	SAIFI	Provincial
2008	1.28	1.78
2009	1.57	1.38
2010	1.08	1.30
2011	1.01	1.38
2012	0.97	1.29

Reliability Statistics for (SAIFI)

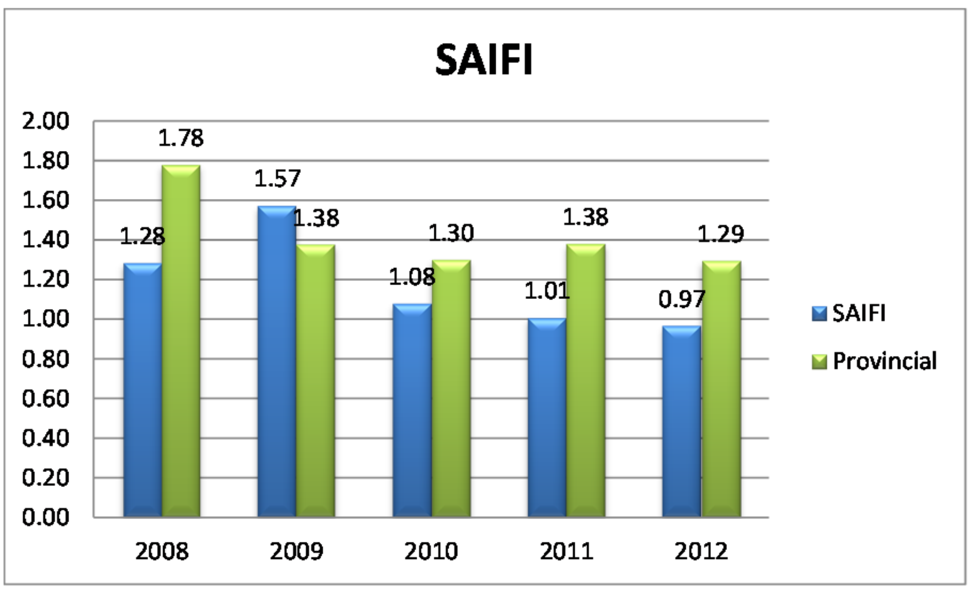
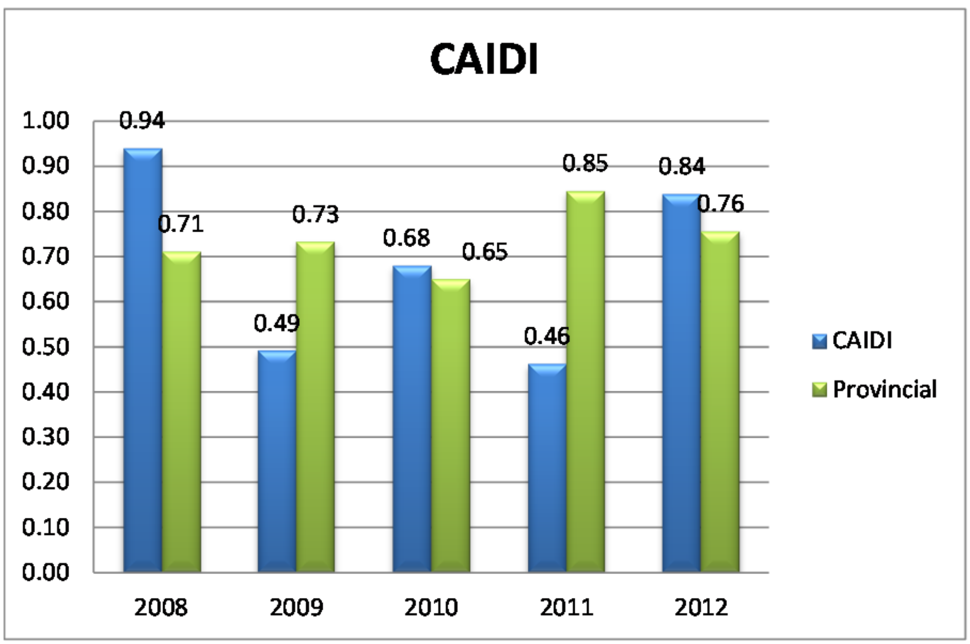


Table 1 -5: Reliability Statistics for (CAIDI)

Year	CAIDI	Provincial
2008	0.94	0.71
2009	0.49	0.73
2010	0.68	0.65
2011	0.46	0.85
2012	0.84	0.76

Reliability Statistics for (CAIDI)



Billing Accuracy and Bill Presentment

In addition to the need to recover operating costs, the investments and a return on investment associated with the ongoing use of smart meters and improving the functionality of the smart meter data, Oakville Hydro's customers have indicated, through customer surveys, that they believe that hydro bills (like other utility and telecom bills) should be billed monthly. Monthly billing is part of the ongoing operation and maintenance request and is expected to increase the revenue requirement by approximately $380,000 per year. The costs associated with providing monthly billing are a significant component of the incremental revenue requirement for the 2014 Test Year. In late 2013, Oakville Hydro will implement a new web presentment tool which will provide its customers with secure access to their energy usage data using a data standard that adheres to strict privacy rules.

Since its last cost of service application, Oakville Hydro has also responded to directives from the Minister of Energy to connect renewable generation, implement Time-of-Use billing, introduce customer service measures for low-income customers and provide emergency financial assistance to low-income customers. Oakville Hydro has also complied with the requirements under the *Ontario One-Call Act* put into legislation in 2012 to mandate utility and infrastructure locates to Province. These costs are included in ongoing system operation and maintenance costs.

B. Budgeting Assumptions

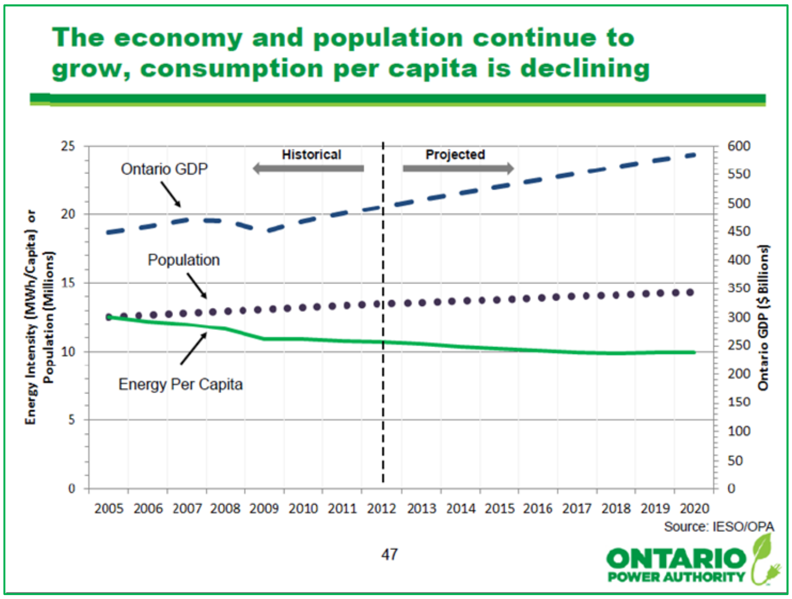
Economic Overview

The budget is a key component of the Business Plan which identifies past successes as well as future initiatives and projections for capital and operating costs. Care is taken to ensure that the capital and operating budgets support Oakville Hydro's Corporate Mission and goals as well as being prudent and financially sustainable. In its 2014 Test Year budget, Oakville Hydro has included the scheduled union rate increase of 1.5% effective July 1, 2014 for its unionized employees and the scheduled wage progression increments for unionized employees based upon service. The 2014 Test Year budget includes an inflationary increase of 2% for non-union employees and an additional increase of approximately 1% for those employees that will be progressing in Oakville Hydro's pay scales as those employees add years of service.

Growth

Oakville Hydro's residential and small commercial customer base continues to grow at a modest pace whereas its industrial base continues to decline. While the population in Oakville Hydro's service area is forecasted to increase by approximately 35% from 2011 to 2031, growth has been slower than forecasted in the Region of Halton in its *Best Planning Estimates of Population, Occupied Dwelling Units and Employment, 2011-2031* published in June 2011. Oakville Hydro anticipates growth to continue at approximately 1% to 2% per year with the majority of the growth occurring in greenfield areas not currently connected to Oakville Hydro's distribution system. This trend is illustrated in the following graph.

In addition, Oakville Hydro is forecasting a decrease in the average consumption per customer as compared with pre-recessionary years. This trend is consistent with both the Ontario and US markets. In its presentation on the Future of Demand Growth, January 8, 2013, the Brattle Group, a consulting firm that provides economic, financial, strategic and regulatory services, examined the causes of the decrease in demand for electricity in the U.S. and concluded that, “The drop in demand growth seems to be permanent, not transitory…”[1] The following graph illustrates the projected decline in consumption per capita in Ontario.



C. Load Forecast and Summary

Oakville Hydro’s forecasted energy consumption for the 2014 Test Year is 65,687,116 kWh or 4.41% higher than its 2010 Board Approved kWh as provided in Table 1-6, Load and Customer Growth – 2014 Test Year vs. 2010 Board Approved. Oakville Hydro’s forecasted number of new customers for the 2014 Test Year, excluding unmetered customers, is 853, or an increase of 1.32% over 2010 Board Approved customer numbers. This illustrates very low growth over a four-year period.

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[1] Webinar presented by Dr. Ahmad Faruqui, principal with The Brattle Group, and Chuck Farmer, Director, Planning Policy and Approvals, OPA http://www.powerauthority.on.ca/sites/default/files/news/Future-of-Demand-Growth-A-Faruqui-C-Farmer.pdf

Table 1-6: Load and Customer Growth – 2014 Test Year vs. 2010 Board Approved

Year	2010 Board Approved	2014 Test Year	kWh Change	Percentage Change
Billed kWh	1,488,242,062	1,553,929,178	65,687,116	4.41%
Number of Customers	64,576	65,428	853	1.32%

Oakville Hydro has used a multivariate regression model to forecast the weather normalized load forecast for the 2014 Test Year. The "total system weather normalized purchased energy forecast" is developed based on a multifactor regression model that incorporates historical load, weather, days in the month and customer data.

D. Rate Base and Capital Plan

Distribution System Plan

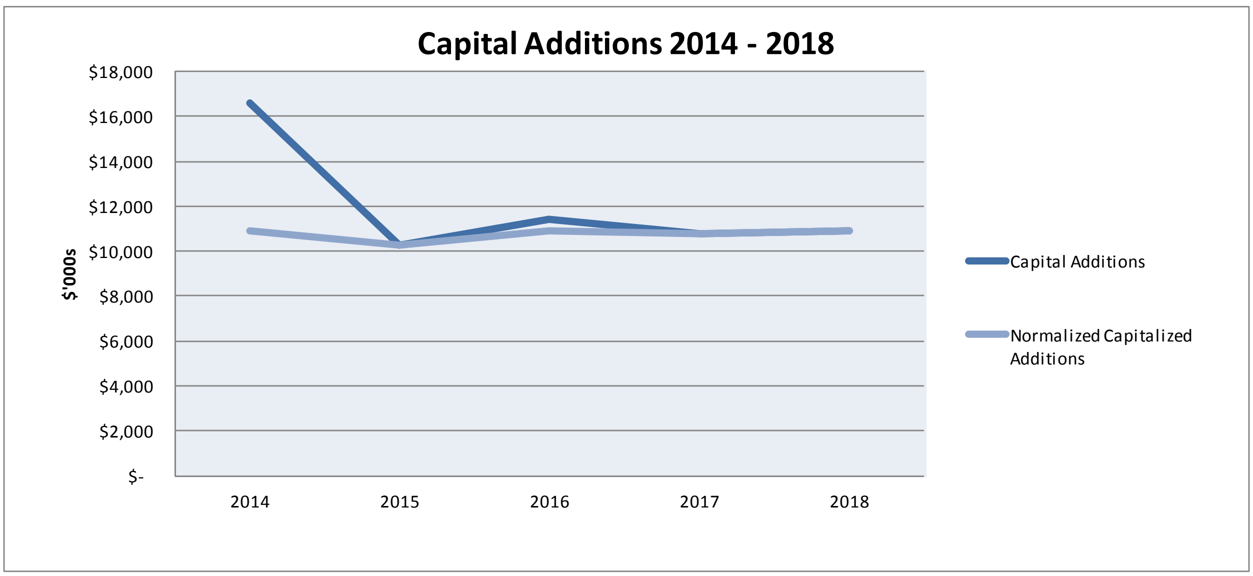
Oakville Hydro's objective is to optimize the performance of its assets at a reasonable cost with due regard for customer service expectations, system reliability, technology innovation and public and employee safety.

As illustrated in the graph on the following page, Oakville Hydro's Capital Expenditure Plan is driven by the requirement for stable and sustainable management of its distribution assets. Oakville Hydro's capital spending is expected to remain reasonably stable for the 2014 to 2018 planning horizon. As renewal occurs, care and consideration are given to incorporating technology and innovative improvements into the distribution assets to deliver reliability, safety and efficiency as well as improvements in customer information and communication.

In the 2014 Test Year, there are two significant exceptions to the generally stable forecast in 2014 for capital spending. The first project is the 2014 planned acquisition of an on-site emergency back-up transformer for Oakville Hydro's Glenorchy Municipal Transformer Station at a cost of $5.0 M. The on-site emergency back-up transformer will ensure long term system reliably for both Oakville and Milton customers if one of the existing transformers were to fail.

Without an available emergency transformer, the delay in replacement puts reliability for both Oakville and Milton customers at risk. The second is the inclusion of an adjustment to fair market value of $738k for a capital lease with a third party for fibre optic cables used as communications infrastructure for Oakville Hydro's distribution system.

In addition, in the year 2016, there is an expected investment for a new Customer Information System ("CIS") as the existing CIS will reach its capacity by 2016. This expenditure will require significant additional analysis and detailed review to ensure a full value to the customer. This cost is not included in the 2014 Test Year revenue requirement. The following chart illustrates planned capital additions for the 2014-2018 period and a "normalized" estimate of 2014 and 2016 expenditures with the above-mentioned items removed.



Capital Expenditures for the 2014 Test Year

As shown in Table 1-7, 2010 Board-Approved Capital Expenditures vs. 2014 Test Year Capital Expenditures below, Oakville Hydro's capital expenditures for the 2014 Test Year are $1,886k or 12.8% higher than the 2010 Board-Approved capital expenditures. There are two major factors that have led to this increase in capital spending:

- The inclusion of the capital costs associated with the acquisition of an on-site emergency back-up transformer increased capital expenditures by $5.0M.

- The inclusion of an adjustment to the value of a capital lease between Oakville Hydro and a third party for optical fibres of $738k.

These increases have been offset by a decrease in capital spending of $3,852k, primarily due to the change in capitalization policies, and a in the remaining capital asset categories.

Table 1-7: Board-Approved Capital Expenditures vs. 2014 Test Year Capital Expenditures

Category	2010 OEB Approved (000s)	2014 Test Year (000's)	Variance (000's)	Variance (%)
System Access	$ 2,372	$ 2,322	$ (51)	-2.1%
System Renewal	8,662	5,980	(2,682)	-31.0%
System Service	781	589	(192)	-24.6%
General Plant	2,906	1,979	(927)	-31.9%
Sub-Total	**$ 14,721**	**$ 10,869**	**$ (3,852)**	**-26.2%**
Glenorchy MTS/Emergency Back-up	-	5,000	5,000	
Indefeasible Right of Use - Fibre Optic	-	738	738	
Total	**$ 14,721**	**$ 16,607**	**$ 1,886**	**12.8%**

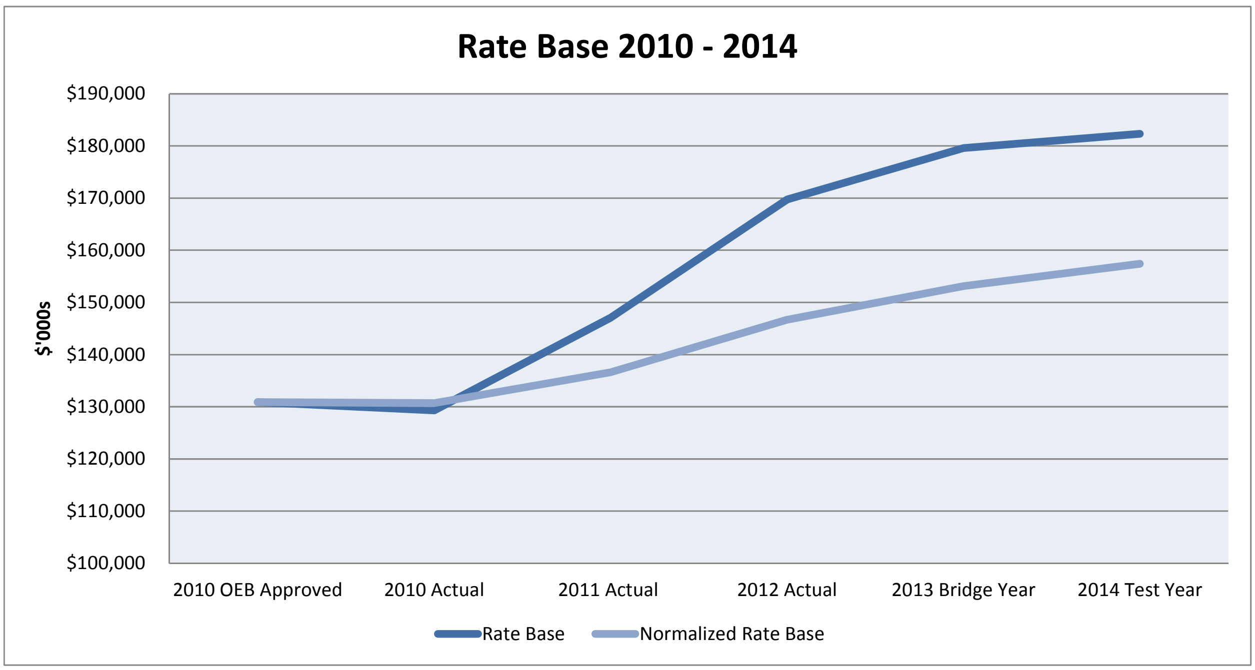
Rate Base

As shown in Table 1-8, 2010 Board-Approved Rate Base vs. 2014 Test Year Rate Base, Oakville Hydro's rate base for the 2014 Test Year has increased by $51,464k or 39% as compared to the 2010 Board-Approved rate base. When normalized to exclude the costs associated with the design and construction of Glenorchy Municipal Transformer Station and the implementation of Smart Meters, as per a directive from the Ministry of Energy, the increase in the rate base is $26,539k or 20% as compared to the 2010 Board-Approved rate base.

Table 1 -8 2010 Board-Approved Rate Base vs. 2014 Test Year Rate Base

	2010 OEB Approved (000s)	2014 Test Year (000s)	Increase (000s)	Increase (%)
Rate Base	$ 130,872	$ 182,335	$ 51,464	39%
Normalized Rate Base	$ 130,872	$ 157,410	$ 26,539	20%

The following graph illustrates the change in rate base for the since Oakville Hydro's 2010 Cost of Service Application.



Smart Grid, Renewable Energy Connections and Regional Planning

Oakville Hydro uses an integrated approach to planning which includes all categories of network investments, network renewal and expansion, renewable generation connection, smart grid development and implementation, and regional planning requirements. This integrated approach optimizes investments that support the outcomes identified by the Board.

Smart Grid

Oakville Hydro will continue to integrate its distribution system (e.g. intelligent switching, remote monitoring and communications, etc.) with operating and information systems. Smart Grid technologies will be incorporated into the analysis of the existing Customer Information Systems ("CIS") capabilities and integration of distribution information for dissemination to customers regarding consumption, reliability and outages in 2016. These changes will expand on current engineering and operating systems, including integration of an Outage Management System ("OMS") currently under development. The level of sophisticated operational capabilities will continue to evolve as part of Smart Grid in order to accept distributed generation while providing increased reliability through switching flexibility and other automated technologies.

Renewable Energy Investments

Oakville Hydro's distribution system has been planned and proactively built and equipped to handle forecasted renewable generation. However, two Hydro One-owned transmission stations have upstream capacity constraints. Oakville Hydro is working with the transmitter to alleviate the restrictions but would have to accept higher short circuit limits than set out in the Transmission System Code. Oakville Hydro plans to study the risk of this change and make a determination to accept, or not accept the higher limits by the end of 2013. If this restriction is lifted, Oakville Hydro does not expect a significant increase in FIT applications, based on information currently available. As a result, Oakville Hydro has not included any capital expenditures specifically related to renewable energy generation in its Distribution System Plan.

Regional Planning

In preparing its Distribution System Plan, Oakville Hydro requested a letter from Hydro One confirming the status of regional planning for the two Regional Planning areas of which Oakville Hydro is a member. Hydro One provided an update on the status of Regional Planning on September 5, 2013 confirming that the Regional Planning Process has not been initiated and a

Regional Infrastructure Plan has not been developed within these regions. Hydro One expects that Regional Planning will be initiated in fourth quarter of 2013. Hydro One and Oakville Hydro have begun discussions regarding Hydro One's preliminary information requirements to initiate the Regional Planning consultation for the two planning regions. Oakville Hydro actively participates with regional distributors, the IESO and Hydro One at an operational level and looks forward to participating at the regional planning level as well.

E. Operations, Maintenance and Administration Expense (OM&A)

Oakville Hydro, like other distributors in Ontario, has gone through significant change since its 2010 Cost of Service application and, as a result, Oakville Hydro's total OM&A costs have increased by $7.6M. As shown in Table 1-9: 2010, the main drivers of this increase are the expensing of burdens previously capitalized ($3.0 million), negotiated wage settlements, wage progressions and benefit increases ($2.3 million), service locates ($0.4 million), Time-of-Use billing and smart meter operation ($0.6 million), monthly billing costs ($0.4 million), operating and maintenance costs associated with the operation of the Glenorchy Municipal Transformer Station ($0.3 million), tree trimming ($0.1) and other miscellaneous programs totaling ($0.5 million).

Table 1-9: 2010 Increase in OM&A for the 2014 Test Year

		Millions	Millions
2010 Board Approved			$11.6
Customer Focus			
	Monthly Billing	$0.4	
	Service Locates	0.4	
Operational Effectiveness			
	Glenorchy Municipal Transformer Station	0.3	
	Tree Trimming	0.1	
Public & Regulatory Responsiveness			
	Smart Meters and TOU Billing	0.6	
	Capitalization Policies	3.0	
All Outcomes			
	Salaries, Wages and Benefits	2.3	
	Other Miscellaneous Outcomes	$ 0.5	
Increase 2014 over 2010			7.6
2014 Test Year OM&A			$ 19.2

Annual compensation increases and progressions for unionized employees are governed by Oakville Hydro's Collective Agreement with the International Brotherhood of Electrical Workers ("IBEW"). Oakville Hydro had a three year agreement that expired June 30, 2013 which provided for annual increases of 3.0%. Effective, July 1, 2013, a new agreement was reached for a four year term with an increase of 2.5% for the period July 2013 to June 2014 and a 1.5% increase for the period July to December 2014. In addition, Oakville Hydro added four full-time equivalent ("FTE") employees since its last Cost of Service application. As shown in Table 1-10, Total Compensation, costs have increased by 20% from the 2010 Board Approved amount to the 2014 Test Year. These additions were related in large part to the requirements for improved skills associated with the technology improvements and initiatives implemented.

Table 1-10: Total Compensation

Category	2010 Board Approved	2014 Test Year	Variance ($)	Variance (%)
Total Compensation	11,262,843	13,545,214	2,282,371	20%

The costs associated with benefit increases, changes to capitalization and burden estimates, increased volume of service locates associated with the *Ontario One Call Act*, Time-of-Use billing and smart meter implementation are generally outside of Oakville Hydro's control. However, Oakville Hydro will continue to review and refine its operations to achieve operating efficiencies and cost sharing opportunities in order to minimize the impact on the customers.

F. Cost of Capital

Oakville Hydro has prepared its Application in accordance with the Board's guidelines provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* (the "2009 Report") issued on December 11, 2009. Oakville Hydro has used the most recent cost of capital parameters issued by the OEB on February 14, 2013 in the *Cost of Capital Parameter Updates for 2013 Cost of Service Applications for Rates Effective May 1, 2013* (the "2013 Cost of Capital Parameters"). There are no deviations from the Board's cost of capital methodology.

G. Cost Allocation and Rate Design

Oakville Hydro has not deviated from the Board's cost allocation and rate design methodology.

Cost Allocation

The data used in the updated cost allocation study is consistent with Oakville Hydro's cost data that supports the proposed 2014 revenue requirement outlined in this Application. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to Oakville Hydro, its engineering records, and its customer and financial information systems. Oakville Hydro has not deviated from the Board's cost allocation methodologies as set out in the following documents:

- *Report of the Board, Review of Electricity Distribution Cost Allocation Policy, March 31, 2011.*
- *Review of Cost Allocation Policy for Unmetered, May 17, 2013.*
- *Allocation of Host Electricity Distributor Costs to Embedded Distributors, July 16, 2013.*

Rate Design

Oakville Hydro is proposing that it is appropriate to maintain the same proportion of fixed and variable revenues as approved by the Board in its 2010 cost of service application. Oakville Hydro is proposing a new rate classification for its Embedded Distributor customer.

H. Deferral and Variance Accounts

Oakville Hydro is requesting approval for the disposition of Group 1 and Group 2 Deferral and Variance Accounts, except account 1508 Other Regulatory Assets- Sub-Account –Deferred IFRS Transition Costs, balance at December 31, 2012 and the forecasted interest through April 30, 2014. The total amount proposed for disposition is $2,549,575. Oakville Hydro is proposing to dispose of the balances of all of the deferral and variance accounts except for the stranded meter variance account over a one-year period. In order to mitigate rate impacts, Oakville Hydro is proposing to dispose of the Stranded Meter variance account over its five year Cost of Service/Incentive Regulation Mechanism term.

Table 1-11: Disposition of Deferral and Variance Accounts

Deferral and Variance Accounts	Total Disposition	Disposition Period
Group One and Group Two Accounts (Excluding GA) (RPP)	($986,693)	One Year
Group One Account (GA) (Non-RPP)	(114,685)	One Year
LRAM Variance Account	169,345	One Year
Stranded Meters	3,331,805	Five Years
CGAAP Accounting Changes	(135,541)	One Year
Incremental Capital Expenditures	285,343	One Year
Total Disposition	$2,549,575	

I. Bill Impacts

In preparing this application, Oakville Hydro has considered the impacts on its customers, with a goal of minimizing those impacts. Customer impacts, including the percentage average Total Bill Impact and Average Dollar Impact are set out below for typical customers in each rate class.

Table1-12: Bill Impact Summary

Rate Class	kWh	kW	Difference	Bill Impact
Residential	800		$ (0.41)	-0.34%
GS < 50 kW	2,000		(20.42)	-6.64%
GS > 50 kW		100	(62.33)	-1.34%
GS > 50 kW		100	(65.83)	-1.41%
GS> 1000 kW		1,200	(2,931.20)	-3.41%
Unmetered	550		(5.15)	-5.99%
Street Lighting		2,000	(11,651.76)	-6.09%
Sentinel Lighting		25	$ (233.87)	-7.28%

Conclusion

Oakville Hydro requests approval of its proposed service revenue requirement of $38,916k which includes, among other items the increase in revenue requirement related to the Glenorchy Municipal Transformer Station, Smart Meter implementation costs and its current capital and operating costs. Oakville Hydro is requesting that its Application be dealt with through a written hearing as Oakville Hydro believes that this is the most cost effective and efficient manner to deal with this proceeding.

Customer Engagement

Oakville Hydro, a 100 year old utility, has always focused on its customers. Oakville Hydro provides an essential service and has an obligation to provide reliable power to the Oakville service area. Over time, customer expectations and requirements change and Oakville Hydro continues to evolve to meet those changes. Technology provides an important tool that allows Oakville Hydro to engage customers. Therefore Oakville Hydro will continue to invest in new technology where appropriate. The energy industry and its policies are also evolving which highlights the need to increase communication with customers. Oakville Hydro believes customer engagement is imperative to understanding and meeting the customers' needs and expectations. As discussed in the summary contained in Exhibit 1, Tab 1, Schedule 1 Service ("Best in the eyes of our customers, employees and stakeholders") and Community ("Enhance the brand of Oakville Hydro and achieve energy savings in the Oakville Community") are two of the four strategic imperatives.

Oakville Hydro constantly strives to improve the customer experience, ensuring regular website updates as well as visibility and involvement at community events. Oakville Hydro wants to connect with customers to ensure that they are aware of Oakville Hydro's various initiatives and gain valuable insight into what they want to learn more about.

Oakville Hydro continually engages its customers in a variety of innovative ways in order to assess whether these methods are effective. Specifically in 2011, Oakville Hydro developed a balanced scorecard which included "Customer Focus" as a measurement. This component of the scorecard created a formalized accountability and outcomes-based objective. It is used to evaluate how Oakville Hydro is performing, based on strategic objectives and assumptions for any given year. Specifically, the objective is to perform a customer survey and, based on the results of the survey, examine ways to improve in the lowest performing categories. Understanding that 100% customer satisfaction is difficult to achieve, the intent is to make improvements to the greatest extent possible.

The following section highlights Oakville Hydro's current customer engagement plans and activities and addresses areas of continuous improvement, in order to achieve increased customer satisfaction and improved public perception of the utility.

Current Engagement Activities

Current customer engagement activities consist of customer surveys, public forums, town council meetings, community outreach events, website improvements, key account manager role and engagement with specific customer interest groups of relevance.

Customer Engagement Surveys

Over the past three years, Oakville Hydro has engaged a third party to conduct customer satisfaction surveys. These customer satisfaction surveys provide information that supports discussions surrounding improving customer service at all levels and departments within Oakville Hydro. The survey asks customers questions on a wide range of topics, including: overall satisfaction with Oakville Hydro, reliability, trust, customer service, outages, billing and corporate image. The results help determine what is being done well and what needs improvement. It also helps to identify the most effective means of communication.

Each year, Oakville Hydro provides input to this third party to enable them to develop questions that will aid in gathering data about customer expectations and needs. This data is then incorporated into Oakville Hydro's planning process and forms the basis of plans to improve customer satisfaction and meet the needs of customers. The final report on these customer satisfaction survey evaluates the level of customer satisfaction and identifies areas of improvement. This report is presented to Oakville Hydro's Board of Directors so that they are aware of customers' expectations and level of satisfaction, and includes discussion on the results in order to facilitate improvement.

Copies of the Executive Summary to the third party consultant's report and the communication to the Board of Directors, are found in Appendix A to this Exhibit. The complete report is provided as an appendix to Exhibit 4. Although the third party consultant reports are identified as being privileged and confidential, Oakville Hydro has obtained the consent of this third party to submit the reports in support of this Application.

Public Forum Town Council Meetings

Another method of communicating with Oakville Hydro's customers is through the Town of Oakville's Town Council meetings. Town Council meetings are open to all residents of Oakville and are recorded on Cogeco TV for viewing on the internet and can be viewed on Town TV at the following link http://www.towntv.ca/. Oakville Hydro's prior practice was to present once per year to Town Council regarding annual financial results and other pertinent information. This has been substantially expanded, and Oakville Hydro's Executive Management Team now presents various important topics that residents (and, in turn, customers) are interested in learning about. This method enables the Town Councillors to relay information regarding Oakville Hydro's operations and plans to their constituents when asked. Table 1-13 provides a summary of topics discussed over the last three years.

Oakville Hydro Electricity Distribution Inc.

Quarterly Update - Town Council Meetings

Date	Topics	Presenter
May 30, 2011	Business update, Time-of-use and 2010 Financial Statements	Rob Lister / Tom Goldie / Lucy Ricci
October 3, 2011	Business update, Glenorchy, Time-of-use, Customer feedback, Distribution system reliability and Asset management, Customer Satisfaction survey results	Rob Lister / Jack Carter / Mike Brown
December 19, 2011	Business update, Distribution system reliability, Time-of-use, Conservation messages	Rob Lister / Mike Brown / Julie Millington
March 5, 2012	Conservation and Demand Management, Time-of use, Residential Programmes available in the community	Julie Millington
May 28, 2012	Business Update, 2011 Highlights, Distribution system, System reliability and performance, Customer feedback, In the community, 2011 financial statements	Rob Lister / Jim Collins
October 9, 2012	Business update, Distribution system reliability and performance, In the community, Conservation and Demand Management, Grid Smart City	Rob Lister
December 17, 2012	Hurricane Sandy Relief, Customer Satisfaction Survey update and Conservation and Demand Management	Rob Lister / Julie Millington
March 4, 2013	Reliability and system performance	Mike Brown
May 27, 2013	Business update, Hurricane Sandy Relief, In the Community, Distribution system, Safety at work and at home, Distribution rates, System reliability and performance, Customer feedback, Grid Smart City,2012 financial statements	Rob Lister / Jim Collins

7

Public Forum for Special Material Projects

Oakville Hydro involves customers in special projects where customer input, education and opinion are requested for valued consideration. Specifically, in 2010 Oakville Hydro held a public session at a local banquet hall inviting the public to become engaged in the proposal to build the Glenorchy Municipal Transformer Station required to service North Oakville. The invitation to the session was published in the local newspaper, a copy of the invitation is provided below. Oakville Hydro believes this transparency was critical to the project's success, allowing customers to provide valuable input to the process. This initiative was well received by customers and Oakville Hydro will consider further sessions in the future, as appropriate.

PUBLIC NOTIFICATION AND NOTICE OF PUBLIC MEETING
CLASS ENVIRONMENTAL ASSESSMENT
NEW 230kV / 27.6kV TRANSFORMER STATION
REGIONAL MUNICIPALITY OF HALTON, ONTARIO

The Study

Oakville Hydro Electricity Distribution Inc. (Oakville Hydro) is a local electricity distribution company in Ontario and is responsible for electrical power delivery to homes and businesses in the Town of Oakville. Oakville Hydro is proposing to build a new transformer station to increase the supply of electricity to the Oakville Hydro service territory. The proposed station will step-down electricity from Hydro One's 230kV high voltage transmission system to lower voltages, so that it can be distributed through Oakville Hydro's electrical system to consumers. The new station is required by spring 2011 to maintain reliable supply and anticipated growth to the Oakville Hydro service area.

The project study area encompasses the Town of Oakville and Town of Milton, north of the 407 and south of Lower Base Line Road, where existing 230kV transmission corridors are present for potential connection. Oakville Hydro has proposed a site off of 6th Line Road (see map).

The project is being undertaken in accordance with the Class Environmental Assessment for Minor Transmission Facilities (Class EA) process approved under the Ontario Environmental Assessment Act.

Public Information Centre

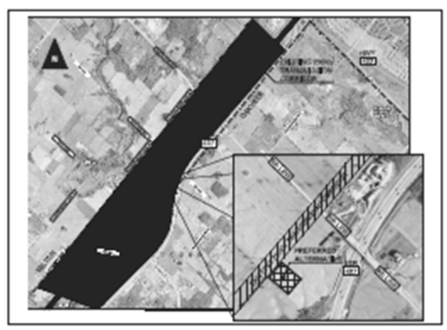
Oakville Hydro is hosting a second Public Information Centre (PIC) to provide interested parties with an opportunity to learn more about the project and provide input to our project team. The PIC is to be held as follows:

Date: Thursday, March 4, 2010
Time: 5:30pm - 8:30pm
Location: SVCC Banquet Hall – Arbour Room
1280 Dundas Street West
Oakville Ontario L6M 4H9

In accordance with the Class EA, draft copies of the Environmental Study Report (ESR) will be available for public review and comment for a 30 day review period from Thursday March 4, 2010 to April 5, 2010 at Oakville Hydro's Head Office located at 861 Redwood Square, Oakville, Ontario L6J 5E3 as well as at the PIC on March 4. Comments are to be submitted to IBI Group at the address noted below.

It is the goal of Oakville Hydro to resolve all comments submitted. Patrick Garel and Jeff Mocha (please see contact info below) will be available throughout the 30 day review period for information to aide in achieving this goal. In the event stakeholder comments or questions are not resolved by Oakville Hydro within the 30-day period, the stakeholder can submit a written request to the Minister of the Environment to "bump-up" the project to an individual environmental assessment in accordance with Part II of the Ontario Environmental Assessment Act. "Bump-up" requests must be received by the Honourable John Gerretsen, Minister of the Environment at 135 St. Clair Avenue West Toronto, ON M4V 1P5 in writing, **no later than 5:00pm** on April 5, 2010. A copy of the request must also be sent to IBI Group at the address noted below.

Information will be collected and used in accordance with the Freedom of Information and Protection of Privacy Act, solely for the purposes of assisting Oakville Hydro in meeting the requirements of the Environmental Assessment Act. This material will be maintained on file for use during the study and may be included in the project documentation. With the exception of personal information, all comments will become part of the Public Record.



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Customer Engagement for Conservation and Demand Management Activities

Oakville Hydro has been actively engaging its customers in Conservation and Demand Management (“CDM") activities since the initiation of third tranche CDM programs. Customer engagement has increased as Oakville Hydro educates it customers about the Ontario Power Authority’s (“OPA’s”) province-wide CDM initiatives designed to enable Oakville Hydro to achieve its CDM targets. Oakville Hydro uses events such as local public events, to speak to a wide range of customers about the conservation programs in place. These opportunities are used to educate customers, allowing them to ask questions, improving energy-decision making and providing them with information that will allow them to be more informed about the distribution system and the energy sector. Oakville Hydro’s focus areas are detailed below:

- Mass market advertising (newspaper advertising, direct mail, billing inserts, on-bill messaging, on-line advertising, etc.).
- Updating the Oakville Hydro website with information on CDM programs and tips for energy saving on Oakville Hydro’s website.
- Sponsorship / participation in local community events, such as home / lifestyle shows to promote CDM programs and awareness. Flyers describing CDM programs are distributed by staff at these events.
- Support for public environmental / conservation awareness events such as Earth Day and Eco-Fest.
- For business customers, “Lunch & Learn” sessions are provided periodically to provide information concerning CDM programs.
- Participation in local Chamber of Commerce events

Each year, Oakville Hydro’s representatives participate in 20 to 30 community events (e.g. Eco-festival, Midnight Madness, Energy Fairs, etc.). These types of events attract the residential class of customers. Although the focus of the event is CDM, there are always customers that would like information on their rates, Time-of-Use billing, and other service related questions.

In order to engage the Commercial and Industrial customers, Oakville Hydro holds "Lunch & Learn" sessions. These sessions are directed to a target audience who are presented with options and programs that may be beneficial to their businesses. Attendees are informed as to programs that are eligible for CDM funding. In 2012, there were three Lunch & Learn sessions held with a 40 person attendance at each session. These sessions will continue depending on the assessment of the CDM programs in place. In 2013, Oakville participated in a joint session with neighboring distributors entitled "Race to Reduce." Generally customers also have an opportunity to talk to Oakville Hydro representative at Chamber of Commerce events as an informal forum for answering questions and immersing Oakville Hydro in the community.

Table 1-13: Lunch and Learn Sessions

Date	Topic
May 30, 2012	Optimizing your Air Conditioning Systems
June 28, 2012	Demand Management Strategies
November 8, 2012	How your business can benefit from Demand Response
February 21, 2013	Race to Reduce

Internal Key Account Manager

Oakville Hydro has a long standing, experienced key account manager who maintains a close relationship with Commercial and Industrial customers. Prior to the market opening, Oakville Hydro had three large use customers (over 5,000 kW). The key account manager spent a significant amount of time providing these customers with energy and demand information as well as providing consultation on how they could achieve energy efficiencies. These high consumption customers are no longer in Oakville's service area and the key account manager has shifted his focus to the 16 customers in the General Service greater than 1,000 kW rate class. These customers have a close relationship with the key account manager who is in contact with them throughout the year to educate them about changing rates, variances to consumption patterns and most importantly how they can reduce energy costs. The key account manager conducts a site visit to each of these customers at least once per year. The relationships that have been built with these customers assures them that Oakville Hydro is looking out for their best interests and can provide them with energy solutions. The balance of the key account manager's time is spent educating and working with the other Industrial and Commercial businesses within Oakville and supporting CDM initiatives for all commercial and industrial customers.

Website (http://www.oakvillehydro.com/ohedi/)

Oakville Hydro's website is intended to be an informative tool to engage customers with activities, changes and initiatives of the utility and the energy industry. This tool provides an abundance of information about Oakville Hydro's Mission and Values and together with energy information that assists customers in making informed decisions. Customers can learn about their electricity rates and various initiatives and make well informed decisions about their electricity use. The website is due for upgrades in 2013 and 2014 and customer bill presentment and presentation will also be improved during this process. (See Customer Education section for expanded details).

Customer Disruption/Project Communication

Oakville Hydro ensures that reasonable communication and engagement is performed in advance of any significant capital renewal and repairs that will affect customers in any way. For example, Oakville Hydro has an ongoing program, the Rear-lot Replacement Program, to replace distribution system equipment on customer premises located in the older pockets of Town. These customers are informed in advance of possible disruptions in service, the project details, the outcome of the project and its benefits. This communication allows Oakville Hydro to clarify areas of concern or provide customers with information that affects their service area.

Customer Engagement Undertaken for the 2014 Cost of Service Application

In preparing its Application, Oakville Hydro engaged various customer groups in advance of the submission of this application. The groups were:

- Streetlighting Customer
- New embedded distributor
- Intervenors in the previous Cost of Service application

Streetlighting Customers

These customers were faced with significant challenges as a result of Oakville Hydro's previous rate application's updated cost allocation methodology. This revised model indicated that the rates charged to streetlighting customers were not representative of the costs to provide distribution services to this rate classification. As a result of previous challenges and the new consultation process on unmetered scattered load released on May 17, 2013, Oakville Hydro has engaged the local municipality in streetlighting discussions. The objective was to educate them on the Board's cost allocation methodology, the methodology for determining the number of streetlight connections, the rate application process the impact on these rates and Oakville Hydro's timing for the filing of the Application. At a subsequent follow up meeting, the proposed rates were presented based on the draft rate Application for submission on October 1, 2013.

Embedded Distributor

In 2013, Oakville Hydro signed a connection agreement with Milton Hydro Distribution Inc. ("Milton Hydro") to connect Milton Hydro to Oakville Hydro's distribution system via two feeders from Oakville Hydro's Glenorchy Municipal Transformer Station, in order to service a portion of Milton Hydro's customers in their service area. Milton Hydro is currently classified as a General Service > 1,000 kW customer, as an interim measure, in the absence of an approved embedded rate class and Milton Hydro is aware that a new class is being proposed in this rate application in Exhibit 7. In June 2013, Oakville Hydro informed Milton Hydro that it intended to discuss the details of the proposed rates and the underlying cost allocation methodology for this rate class and the impact on their distribution rates. On August 29, 2013, Oakville Hydro's regulatory and engineering representatives met with their counterparts at Milton Hydro for these discussions. The meeting was successful, and Milton Hydro supports Oakville Hydro's approach to the allocation of costs to them. A formal letter was received from Milton Hydro and is provided as an appendix to Exhibit 7.

Previous Intervention Interest Groups

Oakville Hydro has continued to engage intervenors of record in its 2010 Cost of Service application throughout the Incentive Regulation Mechanism ("IRM") period. On August 21, 2013, Oakville Hydro had an informal meeting with the Board Case Manager and interested potential intervenors, specifically representatives of the School Energy Coalition, Energy Probe, Vulnerable Energy Consumers Coalition and AMPCO at the Board's offices. The purpose of the meeting was to introduce Oakville Hydro's management and regulatory team, highlight some of the activities that Oakville Hydro has undertaken since its last cost of service application, provide a strategic and corporate governance overview, and present the highlights of the Application. A copy of the presentation is attached as Appendix B to this Exhibit.

Smart Meter and TOU Communication

Prior to, and throughout the Smart Meter implementation, Oakville Hydro participated in a variety of community events. The events provided an effective opportunity to educate and inform the community about Smart Meters and TOU, answer questions and provide take-home materials to customers. The Province's *Get Smart About Smart Meters Answer Book* was distributed at a variety of community events.

In addition to customer education, keeping Oakville Hydro employees informed and educated was important to the success of the Smart Meter rollout. Prior to the implementation of Smart Meters, Oakville Hydro engaged Util-Assist, a Canadian consulting firm, to train Oakville Hydro employees in order to prepare them respond to questions from customers. Attendees were educated on a variety of topics, including why Smart Meters were being implemented, the benefits of Time-of-Use and the impact that Time-of-Use rates would have on customers. Engaged and educated employees are crucial in engaging and educating customers.

Town of Oakville Councillors

Oakville Hydro actively educates and informs the Town of Oakville Mayor and Councillors in the operations and challenges associated with the distribution business. This engagement is, in part, through Town Council update meetings, noted above, and communication to Councillors in the wards in which there are outages.

Challenges and Improvements Required

Oakville Hydro acknowledges that, although it provides customer communication and engagement in a variety of ways, there are areas that could be improved upon. These areas will be addressed below as well as the planned improvements.

Customer Surveys

Oakville Hydro began conducting annual surveys in 2011. This is a relatively new process and Oakville Hydro believes that the variety of questions provided to customers could be enhanced to provide Oakville Hydro with better information regarding customer expectations. Oakville Hydro will continue to conduct these surveys and tailor questions to give internal departments (i.e. Engineering, Finance, Information Technology, Regulatory, Safety and Operations) feedback that will enable them to make sound decisions regarding the provision of service.

Since 2011, the survey results have consistently told Oakville Hydro that power outages and billing problems ("**B**lackouts and **B**ills") are the two issues that are of most concern to customers. Customers' expectations for system reliability have grown along with the advancement of technology. With the onset of computers and smart appliances in homes and businesses, a power outage is critical and customers have little tolerance for even a short power outage. Customers also expect timely and accurate bills that they can understand. Incorrect information, miscalculated balances or bills that are too difficult to understand are a source of customer dissatisfaction.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

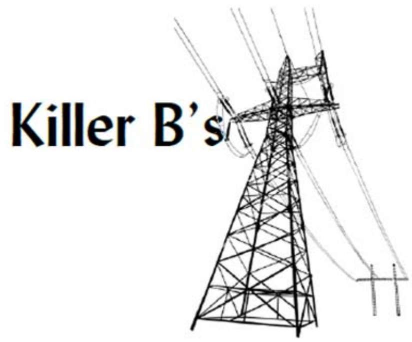
	Oakville Hydro	National	Ontario
2013	37%	41%	35%
2012	39%	44%	46%
2011	30%	43%	43%
2010	-	45%	41%

Base: total respondents / (-) not a participant of the survey year

Percentage of Respondents indicating that they had a Billing problem in the last 12 months

	Oakville Hydro	National	Ontario
2013	9%	8%	10%
2012	7%	12%	13%
2011	9%	10%	16%
2010	-	10%	12%

Base: total respondents/ (-) not a participant of the survey year



Since its last cost of service application Oakville Hydro has introduced a number of programs to improve the level of customer service, system reliability and the efficiency with which these services are delivered.

- **System Reliability**:

  Oakville Hydro created and staffed a new position, Supervisor of Asset Management and began the implementation of a formal Asset Management Program. This program provides a process for the continuous review and refinement of its asset management effectiveness through the evaluation of asset condition, capacity utilization, performance measures, and risk consequence failure analysis as well as the cost efficiency and effectiveness of its performance against its Distribution System Plan.

- **Billing Accuracy:**

  In 2012, Oakville Hydro initiated a "Meter to Cash" Business Process Re-design project which evaluated its meter to cash operations and has introduced a number of internal audit processes and exception reporting to improve billing accuracy. While Oakville Hydro has made many improvements in this area, Oakville Hydro expects to continue to evolve as it implements the recommendations resulting from Meter to Cash ("M2C") process re-design.

In the 2013 survey, Oakville Hydro asked customers about their thoughts about the possibility of a monthly billing cycle. Seventy-two per cent of customers agreed that monthly billing would assist them in managing expenses and 58% of customers believed that most customers would prefer monthly billing. Customers also indicated that they would not be willing to pay more to acquire monthly billing. There is however, an incremental cost to provide this service. Oakville Hydro estimates that it will cost $0.53 per bill to provide monthly billing to its customers and has included a request for recovery in this Application. Monthly billing costs are discussed in detail in Exhibit 4.

Also in 2013, Oakville Hydro asked customers about their knowledge of the Smart Grid. The development of grid-enhancing innovation is an integral part of Oakville Hydro's Distribution System Plans. It is clear from the customer satisfaction survey that customers do not have a clear understanding of what the Smart Grid is and how it might benefit homes and businesses.

When asked if they know about Smart Grid, participants responded in the following way:

- 8% have a fairly good understanding of what it is and how it might benefit homes and businesses;
- 18% have a basic understanding of what it is and how it might work;
- 34% have heard the term but don't know much about it; and
- 39% have not heard the term.

When asked about pursuing Smart Grid opportunities, 52% of participants felt it was important to pursue implementation of the Smart Grid, with 79% saying that they were supportive towards working with neighbouring utilities on Smart Grid initiatives.

Therefore, Oakville Hydro is developing a customer engagement strategy regarding the Smart Grid. This is underway, beginning with Oakville Hydro's engagement with the Oakville Town Council on Smart Grid initiatives, including field automation. The Town Council was briefed on the direction and plan, including:

- Acknowledging the number of existing switch locations that are controlled from the Control Room, the use of SCADA, and the role of each in outage restoration.
- Continued investment in both remotely-controlled switches and switching locations supplied from two sides that automatically operate to select the energized side in the event of an outage (field automation).

Specifically related to Smart Grid, Oakville Hydro's goals are to educate customers on Smart Grid and provide self-serve options so that customers can become even more engaged. These goals will be addressed as follows:

Customer Education

The information provided focuses on communicating the features and benefits of Smart Grid to customers in order to build understanding.

- **Employee education** – Oakville Hydro employees are ambassadors for community messages regarding the Smart Grid
- **Website** – Oakville Hydro's website will include a Smart Grid information webpage where customers can go for information on the Smart Grid and Oakville Hydro initiatives:
    - Summer peak update
    - Unique web address

- Outage summary
- Description of the Smart Grid
- Smart Grid initiatives
- Oakville Hydro's Smart Grid initiatives
- News release
- Survey and feedback

- **Bill Inserts** – Customers will receive a bill insert outlining information regarding Smart Grid and direct them to the website for more information
- **Flyer** – Develop a two-sided information sheet outlining Smart Grid that can be handed out at the front desk and at community events
- **News Release** – A news release describing the Smart Grid and outlining Oakville Hydro's initiatives and innovations to be sent to local media, posted on the website and communicated to staff
- **Community Events** – Promote the Smart Grid at various community events, including distribution of the flyers mentioned above
- **Customer Service Representative Training** – Educate the Customer Service Representatives to be prepared to answer questions and proactively ask questions regarding Smart Grid

Website Development

Oakville Hydro's website design and information has not kept up with technology. Significant enhancements are planned to ensure that customers can more easily obtain information that they require. One initiative is providing real-time visual power outage information and estimated restoration times. In addition, providing a website that is easier to navigate, will provide Oakville Hydro with key touch points that customers can easily access.

- **Online Applications** – Oakville Hydro plans to streamline the application process in order to make application forms easily accessible online, to reduce response and processing time, improve process errors, and decrease customer interaction by phone, fax and in the office. Oakville Hydro's goal is to make the customer process of interacting with Oakville Hydro both easy and convenient.

- **Web presentment tool for Time-of-Use data** – Designed to provide Oakville Hydro customers with secure, real time access to Time-of-Use and Account Data. The web portal will include the following features:
    - Usage charts and data downloads
    - Hourly usage charts
    - Price plan comparison
    - Mobile access
    - Energy profiles
    - Usage comparison
    - Transaction history
    - Ebill presentment (currently eCare)
    - Alerts (high bill notifications, etc.)
    - Green Button (the Green Button initiative is an industry-led effort to provide electricity customers with easy access to their energy usage data in a consumer-friendly and computer-friendly format via a "Green Button" on electric utilities' website.)

Replacing the existing system is a significant upgrade for customers, giving them the tools to monitor their consumption and make informed decisions.

Social Media

Social media (such as Facebook, Twitter, mobile Apps and more) is important to many of Oakville Hydro's customers. Oakville Hydro is assessing its options to deliver information and customer engagement while maintaining required security and privacy levels. Social media initiatives will be carefully rolled out during 2013 and improved upon in 2014 based, on feedback from customers.

Commercial and Industrial (GS > 1,000 kW) Customer Meetings

Commercial customers have a significant interest in the energy and power costs required to effectively run their business. The key account manager is their first point of contact for rates, billing and consumption concerns or questions on various charges and works with them and to resolve concerns or issues. In the past five years, this class of customers has been formally invited to sessions specifically for Province-wide Conservation and Demand Management initiatives that have been well received. This fall, Oakville Hydro has scheduled information sessions for this group of customers on energy and distribution rates, changes in the energy industry and how this will directly impact them.

Customer Communication and Data

Oakville Hydro plans to establish new communication channels with customers and provide on demand access to information, including consumption and outage details.

- **Interactive Voice Response (IVR)** – Provides customers with the ability to access their information on the phone via voice prompts and have access to their account details and data, in addition to the development of improved tools for communicating outage information.
- **Data Access** – Facilitates customer access to consumption data in an electronic format for the purpose of both analyzing and sharing as part of the web redesign (e.g. the Green Button). This program is expected to require additional investment in or around 2015 and 2016 for integration of this data with the existing, (or a new), customer information system.

Corporate Scorecard

Oakville Hydro will consider evolving the “Customer Focus” area of its corporate scorecard for opportunities to include additional or different metrics to ensure that there is added value for customers. Consideration will be given to incorporating some of the Board’s measures into the corporate scorecard, if appropriate.

Conclusion

Oakville Hydro’s engagement with its wide range of customers continues with a forward looking vision of continuous improvement and increased satisfaction. Customer satisfaction is one of Oakville Hydro’s corporate goals. “Our customer continues to change and so should we.”

Financial Information

Audited Financial Statements – 2011 and 2012:

Oakville Hydro's non-consolidated 2011 and 2012 audited financial statements accompany this Schedule as part of Appendix C.

Reconciliation Between Financial Statements and Regulatory Accounting

The reconciliation required between financial statements and regulatory accounting are provided in the tables below.

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Balance Sheet
December 31, 2010
(in thousands of dollars)

	Audited Financial Statements	Adjustments	2010 Regulatory Filing	Notes
ASSETS				
CURRENT				
Cash and cash equivalents	$ 1,618		$ 1,618	
Accounts receivable	31,103	163	31,266	Note 1
Inventories	3,632		3,632	
Prepaid expenses	519		519	
	36,872	**163**	**37,035**	
OTHER				
Due from related parties	-			
Long term receivable	163	(163)	-	
Future income taxes	22,445		22,445	
	22,608	**(163)**	**22,445**	
CAPITAL ASSETS	125,216		125,216	
	$ 184,696	**$ -**	**$ 184,696**	
LIABILITIES				
CURRENT				
Accounts payable and accrued charges	$ 27,965		$ 27,965	
Consumer deposits	5,008		5,008	
Capital lease obligation	274		274	
	33,247	**-**	**33,247**	
OTHER				
Due to related parties	6,632		6,632	
Regulatory liabilities	17,383	9	17,392	Note 2
Post employment benefits	7,473		7,473	
Capital lease obligation	12,285		12,285	
Long-term debt	67,946		67,946	
	111,719	**9**	**111,728**	
	144,966	**9**	**144,975**	
SHAREHOLDER'S EQUITY				
SHARE CAPITAL				
Authorized and issued - 1,000 common shares	54,108		54,108	
Retained earnings (deficit)	(14,378)		(14,378)	
	39,730	**-**	**39,730**	
	$ 184,696	**$ 9**	**$ 184,705**	

Notes:

1 Reclassification of long-term receivable for GAAP (163K)

2 Correction to OPA funded CDM expenditures 9K (recorded incorrectly in OEB account 1565 for F/S)

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Statement of Operations and Retained Earnings (Deficit)
Year ended December 31, 2010
(in thousands of dollars)

	Audited Financial Statements	Adjustments	2010 Regulatory Filing	Notes
REVENUE				
Energy and distribution revenue	$ 160,191		$ 160,191	
Cost of power	(130,385)		(130,385)	
Net distribution revenue	**29,806**	-	**29,806**	
Other revenues	4,821	(217)	4,604	Note 1,2,3
	34,627	**(217)**	**34,410**	
EXPENSES				
Personnel costs	10,723		10,723	
Contract Services	2,070		2,070	
Property and occupancy costs	1,098		1,098	
Material costs	383		383	
Other costs	4,477	(290)	4,187	Note 2
Costs allocated to capital	(5,793)		(5,793)	
	12,958	**(290)**	**12,668**	
EARNINGS BEFORE AMORTIZATION, INTEREST AND INCOME TAXES	**21,669**	**73**	**21,742**	
AMORTIZATION	(9,997)		(9,997)	
INTEREST	(5,344)	(82)	(5,426)	Note 3
INCOME BEFORE INCOME TAXES	**6,328**	**(9)**	**6,319**	
PROVISION FOR INCOME TAXES	**1,673**		1,673	
NET INCOME	**4,655**	**(9)**	**4,646**	
RETAINED EARNINGS (DEFICIT), BEGINNING OF YEAR as previously stated	(14,771)		(14,771)	
CHANGE IN POLICY RECOGNIZING FUTURE TAXES	-		-	
WRITE OFF BALANCE OF OLD CAPITAL LEASE	(3,581)		(3,581)	
IRU PURCHASE IN EXCESS OF NET BOOK VALUE	(681)		(681)	
DEFICIT, BEGINNING OF YEAR as restated	**(19,033)**	-	**(19,033)**	
Less: Dividends	-			
	(19,033)	-	**(19,033)**	
RETAINED EARNINGS (DEFICIT), END OF YEAR	**$ (14,378)**	**$ (9)**	**$ (14,387)**	

Notes:
1 Correction to OPA funded CDM expenditures 9K (recorded incorrectly in OEB account 1565 for F/S)
2 Reclassificaiton of Collection Charges to revenue for GAAP (290K)
3 Reclassificaiton of interest revenue on deferral & variance accounts for F/S reporting (82K)

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Balance Sheet
December 31, 2011
(in thousands of dollars)

	Audited Financial Statements	Adjustments	2011 Regulatory Filing	Notes
ASSETS				
CURRENT				
Cash and cash equivalents	$ -		$ -	
Accounts receivable	37,033		37,033	
Inventories	4,068		4,068	
Prepaid expenses	345		345	
	41,446	**-**	**41,446**	
OTHER				
Due from related parties	9,851		9,851	
Long term receivable	137		137	
Future income taxes	20,557		20,557	
	30,545	**-**	**30,545**	
CAPITAL ASSETS	141,441		141,441	
	$ 213,432	**$ -**	**$ 213,432**	
LIABILITIES				
CURRENT				
Bank overdraft	$ 16,430		$ 16,430	
Accounts payable and accrued charges	27,188		27,188	
Consumer deposits	5,169		5,169	
Capital lease obligation	299		299	
	49,086	**-**	**49,086**	
OTHER				
Due to related parties	-		-	
Regulatory liabilities	10,071		10,071	
Post employment benefits	7,667		7,667	
Capital lease obligation	11,986		11,986	
Long-term debt	67,946	(67,946)	0	Note 1
Advances From Associated Companies		67,946	67,946	Note 1
	97,670	**-**	**97,670**	
	146,756	**-**	**146,756**	
SHAREHOLDER'S EQUITY				
SHARE CAPITAL				
Authorized and issued - 1,407 common shares	76,108		76,108	
Deficit	(9,432)		(9,432)	
	66,676	**-**	**66,676**	
	$ 213,432	**$ -**	**$ 213,432**	

Notes:

1 Reclassificaiton advised by OEB (67,946K)

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Statement of Operations and Deficit
Year ended December 31, 2011
(in thousands of dollars)

	Audited Financial Statements	Adjustments	2011 Regulatory Filing	Notes
REVENUE				
Energy and distribution revenue	$ 170,215		$ 170,215	
Cost of power	(138,130)		(138,130)	
Net distribution revenue	**32,085**		**32,085**	
Other revenues	3,474	(116)	3,358	Note 1 , 2
	35,559	**(116)**	**35,443**	
EXPENSES				
Personnel costs	11,442		11,442	
Contract services	3,211		3,211	
Property and occupancy costs	1,176		1,176	
Material costs	289		289	
Other costs	4,552	(291)	4,261	Note 1
Costs allocated to capital	(6,087)		(6,087)	
	14,583	**(291)**	**14,292**	
EARNINGS BEFORE AMORTIZATION, INTEREST AND INCOME TAXES	20,976		20,976	
AMORTIZATION	(10,220)		(10,220)	
INTEREST	(5,834)	(175)	(6,009)	Note 2
INCOME BEFORE INCOME TAXES	**4,922**		**4,747**	
PROVISION FOR INCOME TAXES	(24)		(24)	
NET INCOME	**4,946**	**-**	**4,771**	
DEFICIT, BEGINNING OF YEAR	**(14,378)**	**-**	**(14,378)**	
Less: Dividends	**-**		-	
	(14,378)	**-**	**(14,378)**	
DEFICIT, END OF YEAR	**$ (9,432)**	**$ -**	**$ (9,432)**	

Notes:

1 Reclassificaiton of Collection Charges to revenue for GAAP (291K)

2 Reclassificaiton of interest revenue on deferral & variance accounts for F/S reporting (175K)

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Balance Sheet
December 31, 2012
(in thousands of dollars)

	Audited Financial Statements	Adjustments	2012 Regulatory Filing	Notes
ASSETS				
CURRENT				
Cash and cash equivalents	$ 15,769		$ 15,769	
Accounts receivable	33,362	-186	33,176	Note 1
Inventories	3,216		3,216	
Prepaid expenses	470		470	
	52,817		**52,631**	
OTHER				
Due from related parties	-		-	
Other Non-Current Assets	-	186	186	Note 1
Future income taxes	19,891		19,891	
	19,891		**20,077**	
CAPITAL ASSETS	153,506		153,506	
	$ 226,214		**$ 226,214**	
LIABILITIES				
CURRENT				
Bank overdraft	$ -		$ -	
Accounts payable and accrued charges	23,928		23,928	
Consumer deposits	4,639		4,639	
Current portion-long term debt	390		390	
Capital lease obligation	325		325	
	29,282		**29,282**	
OTHER				
Regulatory liabilities	17,038		17,038	
Post employment benefits	7,641		7,641	
Capital lease obligation	11,661		11,661	
Long-term debt	89,492		89,492	
	125,832		**125,832**	
	155,114		**155,114**	
SHAREHOLDER'S EQUITY				
SHARE CAPITAL				
Authorized and issued - 1,407 common shares	76,108		76,108	
Deficit	(5,008)		(5,008)	
	71,100		**71,100**	
	$ 226,214		**$ 226,214**	

Notes:
1 Reclassificaiton of long term receivable for GAAP (186K)

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Statement of Operations and Deficit
Year ended December 31, 2012
(in thousands of dollars)

	Audited Financial Statements	Adjustments	2012 Regulatory Filing	Notes
REVENUE				
Energy and distribution revenue	$ 186,483	(3,839)	$ 182,644	Note 1
Cost of power	(149,134)		(149,134)	
Net distribution revenue	37,349	(3,839)	33,510	
Other revenues	3,813	(1,558)	2,255	Note 2 & 5
	41,162	**(5,397)**	**35,765**	
EXPENSES				
Personnel costs	12,138		12,138	
Contract services	2,882		2,882	
Property and occupancy costs	1,102		1,102	
Material costs	314		314	
Other costs	6,045		6,045	
Costs allocated to capital	(5,375)		(5,375)	
	17,106	**(2,799)**	**14,307**	Note 1,2,3,4
EARNINGS BEFORE AMORTIZATION, INTEREST AND INCOME TAXES	**24,056**	**(2,597)**	**21,459**	
AMORTIZATION	(13,352)	1,631	(11,721)	Note 1
INTEREST	(5,566)	(127)	(5,693)	Note 5
INCOME BEFORE INCOME TAXES	**5,138**	**(1,094)**	**4,044**	
PROVISION FOR INCOME TAXES	714		714	
EXTRAORDINARY ITEMS		1,094	1,094	Note 1
NET INCOME	**4,424**		**4,424**	
RETAINED EARNINGS (DEFICIT), BEGINNING OF YEAR as previously stated	-			
CHANGE IN POLICY RECOGNIZING FUTURE TAXES	-			
WRITE OFF BALANCE OF OLD CAPITAL LEASE (Note 9)	-			
IRU PURCHASE IN EXCESS OF NET BOOK VALUE	-			
DEFICIT, BEGINNING OF YEAR	**(9,432)**		**(9,432)**	
Less: Dividends	-			
	(9,432)		**(9,432)**	
DEFICIT, END OF YEAR	**$ (5,008)**		**$ (5,008)**	

Notes:
1 Cumulative pre-2012 effect of the Smart Meter Variance Accounts to Extraordinary Items (non-recurring) (3,839K).
2 Administrative Credits Recorded as Revenues for Financial Statements (1,215K)
3 Reclassification of bad debt provisions associated with billable/miscellaneous revenues (464K)
4 Immaterial CDM Costs in administrative costs (6K)
5 Interest earned on RSVA netted against interest income for financial statement (-127K)

2012 Annual Report and Management's Discussion for Oakville Hydro Corporation

Oakville Hydro Corporation's 2012 financial statement is provided as Appendix C. Oakville Hydro has not included an annual report or Management discussion and analysis, as its parent company, Oakville Hydro Corporation, only prepares notes to the financial statements.

Rating Agency Reports

Oakville Hydro does not obtain rating agency reports.

Prospectuses and Information Circulars for Recent and Planned Public Issuances

Oakville Hydro has no planned or current public issuances.

Materiality Threshold

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued by the Board July 17, 2013 sets out the materiality levels based on the magnitude of the revenue requirement. Oakville Hydro's revenue requirement is greater than $10 million and less than $200 million, therefore its materiality level is 0.5% of distribution revenue requirement. Oakville Hydro's materiality threshold for the 2014 Test Year is $184,402. Oakville Hydro has provided analysis of all variances greater than $180,000.

Table 1-14: Materiality Thresholds

Description	2010 Actual	2011 Actual	2012 Actual	2013 Bridge Year	2014 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Distribution Revenue Requirement	$28,887,142	$31,874,719	$37,505,196	$37,324,935	$36,880,386
Materiality - 0.5 %	$144,436	$159,374	$187,526	$186,625	$184,402

Administration

Statement of Publication

Oakville Hydro's customers, including Milton Hydro and 28 load transfer customers in Milton Hydro Electricity Distribution Inc.'s service area, will be affected by this Application. Oakville Hydro will publish the notice of application in the Oakville Beaver. To the best of Oakville Hydro's knowledge, the Oakville Beaver is the local newspaper having the highest circulation in Oakville Hydro's service area with circulation of approximately 52,100 unpaid subscribers.

Interested parties can view the Application on Oakville Hydro's website at http://www.oakvillehydro.com/ohedi.

Contact Information

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Required Approval Date

Oakville Hydro requires an approved rate order by April 15, 2014 in order to implement the requested rate order by the requested date of May 1, 2014.

Bill Impacts

In preparing this Application, Oakville Hydro has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, Oakville Hydro notes that for the 2014 Test Year, the proposed revenue to cost ratio for each rate class falls within the threshold defined by the Board in its Review of Electricity Distribution Cost Allocation Policy, March 31, 2011.

Customer impacts, including the per cent average Total Bill Impact and Average Dollar Impact, which include revised distribution rates (monthly service charge and volumetric rates), revised low voltage rates, revised retail transmission rates, revised loss factors, LRAM rate riders, and regulatory asset rate riders to dispose of the balances in the Deferral and Variance Accounts requested in this Application are set out below, for typical Residential (800 kWh per month) and Commercial (2,000 kWh per month) customers. A complete listing of bill impacts for all customer classes at various levels of consumption is provided in Exhibit 8.

The distribution only bill impact to be used for the notice of application for a typical Residential customer using 800 kWh per month is an increase of $2.12. The distribution only bill impact to be used for the notice of application for a typical General Service < 50 kW using 2,000 kWh per month is a decrease of $14.00.

Table 1-15: Bill Impact: Residential

Customer Class: Residential

TOU / non-TOU: TOU

Consumption 800 kWh ◉ May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 13.11	1.00	$ 13.11	$ 15.81	1	$ 15.81	$ 2.70	20.59%
Smart Meter Rate Adder	Monthly	2.49	1.00	2.49		1	0.00	-2.49	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0143	800.00	11.44	0.0172	800.00	13.76	2.32	20.28%
Smart Meter Disposition Rider	Monthly	-0.0300	1.00	-0.03		800.00	0.00	0.03	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0003	800.00	0.24	0.0002	800.00	0.16	-0.08	-33.33%
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0018	800.00	1.44		800.00	0.00	-1.44	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	800.00	-0.24		800.00	0.00	0.24	-100.00%
Rate Rider for disposition Stranded Meter	Monthly	0.0000	1.00	0.00	0.7600	1.00	0.76	0.76	
Rate Rider for PP & E	per kWh		800.00	0.00	-0.0001	800.00	-0.08	-0.08	
ICM Rate Rider	per kWh		800.00	0.00	0.0002	800.00	0.16	0.16	
			800.00	0.00		800.00	0.00	0.00	
			800.00	0.00		800.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 28.45**			**$ 30.57**	**$ 2.12**	**7.45%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	800.00	0.24	-0.0002	800.00	-0.16	-0.40	-166.67%
			800.00	0.00		800.00	0.00	0.00	
			800.00	0.00		800.00	0.00	0.00	
			800.00	0.00		800.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	800.00	0.16	0.0004	800.00	0.32	0.16	100.00%
Line Losses on Cost of Power	per kWh	0.0839	30.16	2.53	0.0839	29.76	2.50	-0.03	-1.33%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 32.17**			**$ 34.02**	**$ 1.85**	**5.74%**
RTSR - Network	per kWh	0.0080	830.16	6.64	0.0072	829.76	5.97	-0.67	-10.04%
RTSR - Line and Transformation Connection	per kWh	0.0055	830.16	4.57	0.0036	829.76	2.99	-1.58	-34.58%
Sub-Total C - Delivery (including Sub-Total B)				**$ 43.38**			**$ 42.98**	**-$ 0.40**	**-0.92%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	830.16	3.65	0.0044	829.76	3.65	0.00	-0.05%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	830.16	1.00	0.0012	829.76	1.00	0.00	-0.05%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	800	5.60	0.0070	800	5.60	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	512	34.30	0.0670	512	34.30	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	144	14.98	0.1040	144	14.98	0.00	0.00%
TOU - On Peak	per kWh	0.1240	144	17.86	0.1240	144	17.86	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	600	45.00	0.0750	600	45.00	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	200	17.60	0.0880	200	17.60	0.00	0.00%
Total Bill on TOU (before Taxes)				**121.01**			**120.61**	**-0.40**	**-0.33%**
HST		13%		15.73	13%		15.68	-0.05	-0.33%
Total Bill (including HST)				136.74			136.29	-0.45	-0.33%
***Ontario Clean Energy Benefit* [1]**				-13.67			-13.63	0.04	-0.29%
Total Bill on TOU (including OCEB)				**$ 123.07**			**$ 122.66**	**-$ 0.41**	**-0.34%**
Total Bill on RPP (before Taxes)				**116.48**			**116.08**	**-0.40**	**-0.34%**
HST		13%		15.14	13%		15.09	-0.05	-0.34%
Total Bill (including HST)				131.62			131.17	-0.45	-0.34%
***Ontario Clean Energy Benefit* [1]**				-13.16			-13.12	0.04	-0.30%
Total Bill on RPP (including OCEB)				**$ 118.46**			**$ 118.05**	**-$ 0.41**	**-0.35%**

Loss Factor (%) 3.77% 3.72%

Table 1-16: Bill Impact: General Service < 50 kW

Consumption 2,000 kWh

◉ May 1 - October ○ November 1 - April 30 (Select this radio button for applications filed after Oct 31)

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 32.24	1.00	$ 32.24	$ 31.01	1	$ 31.01	-$ 1.23	-3.82%
Smart Meter Rate Adder	Monthly	7.33	1.00	7.33		1	0.00	-7.33	-100.00%
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
			1.00	0.00		1	0.00	0.00	
Distribution Volumetric Rate	per kWh	0.0142	2,000.00	28.40	0.0137	2,000.00	27.40	-1.00	-3.52%
Smart Meter Disposition Rider	Monthly	4.6300	1.00	4.63		1.00	0.00	-4.63	-100.00%
LRAM & SSM Rate Rider	per kWh	0.0000	2,000.00	0.00	0.0001	2,000.00	0.20	0.20	
Rate Rider for recovery of Incremental Capital Costs	per kWh	0.0015	2,000.00	3.00		2,000.00	0.00	-3.00	-100.00%
Rate Rider for Application of Tax Change (2013)	per kWh	-0.0003	2,000.00	-0.60		2,000.00	0.00	0.60	-100.00%
Rate Rider for disposition Stranded Meter	Monthly		1.00	0.00	2.1900	1.00	2.19	2.19	
Rate Rider for PP & E	per kWh		2,000.00	0.00	-0.0001	2,000.00	-0.20	-0.20	
ICM Rate Rider	per kWh		2,000.00	0.00	0.0002	2,000.00	0.40	0.40	
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
Sub-Total A (excluding pass through)				**$ 75.00**			**$ 61.00**	**-$ 14.00**	**-18.67%**
Deferral/Variance Account Disposition Rate Rider	per kWh	0.0003	2,000.00	0.60	-0.0003	2,000.00	-0.60	-1.20	-200.00%
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
			2,000.00	0.00		2,000.00	0.00	0.00	
Low Voltage Service Charge	per kWh	0.0002	2,000.00	0.40	0.0003	2,000.00	0.60	0.20	50.00%
Line Losses on Cost of Power	per kWh	0.0839	75.40	6.33	0.0839	74.40	6.24	-0.08	-1.33%
Smart Meter Entity Charge	Monthly	0.7900	1.00	0.79	0.7900	1	0.79	0.00	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 83.12**			**$ 68.03**	**-$ 15.08**	**-18.15%**
RTSR - Network	per kWh	0.0074	2,075.40	15.35	0.0067	2,074.40	13.90	-1.46	-9.50%
RTSR - Line and Transformation Connection	per kWh	0.0050	2,075.40	10.38	0.0033	2,074.40	6.85	-3.53	-34.03%
Sub-Total C - Delivery (including Sub-Total B)				**$ 108.85**			**$ 88.78**	**-$ 20.07**	**-18.44%**
Wholesale Market Service Charge (WMSC)	per kWh	0.0044	2,075.40	9.13	0.0044	2,074.40	9.13	0.00	-0.05%
Rural and Remote Rate Protection (RRRP)	per kWh	0.0012	2,075.40	2.49	0.0012	2,074.40	2.49	0.00	-0.05%
Standard Supply Service Charge	Monthly	0.2500	1	0.25	0.2500	1	0.25	0.00	0.00%
Debt Retirement Charge (DRC)	per kWh	0.0070	2000	14.00	0.0070	2000	14.00	0.00	0.00%
TOU - Off Peak	per kWh	0.0670	1280	85.76	0.0670	1280	85.76	0.00	0.00%
TOU - Mid Peak	per kWh	0.1040	360	37.44	0.1040	360	37.44	0.00	0.00%
TOU - On Peak	per kWh	0.1240	360	44.64	0.1240	360	44.64	0.00	0.00%
Energy - RPP - Tier 1	per kWh	0.0750	750	56.25	0.0750	750	56.25	0.00	0.00%
Energy - RPP - Tier 2	per kWh	0.0880	1250	110.00	0.0880	1250	110.00	0.00	0.00%
Total Bill on TOU (before Taxes)				**302.56**			**282.48**	**-20.08**	**-6.64%**
HST		13%		39.33	13%		36.72	-2.61	-6.64%
Total Bill (including HST)				341.90			319.21	-22.69	-6.64%
Ontario Clean Energy Benefit [1]				-34.19			-31.92	2.27	-6.64%
Total Bill on TOU (including OCEB)				**$ 307.71**			**$ 287.29**	**-$ 20.42**	**-6.64%**
Total Bill on RPP (before Taxes)				**300.97**			**280.89**	**-20.08**	**-6.67%**
HST		13%		39.13	13%		36.52	-2.61	-6.67%
Total Bill (including HST)				340.10			317.41	-22.69	-6.67%
Ontario Clean Energy Benefit [1]				-34.01			-31.74	2.27	-6.67%
Total Bill on RPP (including OCEB)				**$ 306.09**			**$ 285.67**	**-$ 20.42**	**-6.67%**

	Current	Proposed
Loss Factor (%)	3.77%	3.72%

Form of Hearing Requested

Oakville Hydro is requesting that its Application be dealt with through a written hearing as Oakville Hydro believes that this is the most cost effective and efficient manner to deal with this proceeding.

Specific Approvals Requested

In this proceeding, Oakville Hydro is requesting the following approvals:

- Approval to charge rates effective May 1, 2014 and January 1 in subsequent years to recover a base revenue requirement of $38,916,139 which includes a revenue deficiency of $5,380,890 as set out in Exhibit 6. Oakville Hydro is requesting an effective date of January 1 beginning January 1, 2015 to align the rate year with the budget year and to provide customers with greater transparency by separating distribution rate changes from commodity price changes. The schedule of proposed rates is set out in Exhibit 8;

- Approval for the inclusion of the difference between the net book value for a fibre optic network lease included in Oakville Hydro's 2010 Cost of Service Application (EB-2009-0271) the net appraised value as set out in Exhibit 2;

- Approval for the inclusion of the difference between the capital expenditures proposed for the Glenorchy Municipal Transformer Station in Oakville Hydro's Incremental Capital Module Claim (EB-2010-0104) and the amount actually spent on the station in its rate base as set out in Exhibit 2;

- Approval of revised low voltage rates to be included in the standard distribution rates as proposed and described in Exhibit 8;

- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8;

- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the Board Decision and Order in the matter of Oakville Hydro's 2013 Distribution Rates (EB-2012-0154);

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the Board Decision and Order in the matter of Oakville Hydro's 2013 Distribution Rates (EB- EB-2012-0154);

- Approval to charge the standard Specific Charge of $30 for service calls during regular hours and $165 after regular hours when providing special or extra services not included in the standard level of service that are provided upon a customer's request;

- Approval to dispose of the following Deferral and Variance Account balances as at December 31, 2012 period using the method of recovery described in Exhibit 9:

Account Descriptions	Account Number	Disposition Period (Yyears)
Group 1 Accounts		
LV Variance Account	1550	1
RSVA - Wholesale Market Service Charge	1580	1
RSVA - Retail Transmission Network Charge	1584	1
RSVA - Retail Transmission Connection Charge	1586	1
RSVA - Power (excluding Global Adjustment)	1588	1
RSVA - Power - Sub-account - Global Adjustment	1589	1
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	1
Group 2 Accounts		
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	1
Retail Cost Variance Account - Retail	1518	1
Smart Grid OM&A Deferral Account	1535	1
Retail Cost Variance Account - STR	1548	1
Smart Meter Capital and Recovery Offset Variance - Sub-account - Stranded Meter Costs	1555	5
PILs and Tax Variance for 2006 and Subsequent Years	1592	1

- Approval for the disposition of the difference in 2013 Net Book Value of Property, Plant and Equipment, as a result of Oakville Hydro's changes to depreciation rates and capitalization policy recorded in Account 1576, CGAAP Accounting Changes over a one year period;

- Approval of the proposed loss factor of 1.0372 as set out in Exhibit 3;

- Approval to recover amounts related to LRAM amounts related to activities in 2011 and 2012 over a one year period, using the method of recovery described in Exhibit 9;

- Approval to establish a new Embedded Distributor rate class consistent with the approach approved by the Board in EB-2010-0063. In that Decision the Board approved Brant County Power's request as an embedded distributor within Brantford Power Inc. to be separated as a customer from the General Service > 50 kW rate class and be classified as a member of a new Embedded Distributor rate class.

- In the event the Board is unable to issue a Decision and Order in this proceeding before April 15, 2014 for implementation of rates as of May 1, 2014, Oakville Hydro requests that the Board issue an Interim Order approving its current distribution rates and other charges effective May 1, 2014.

Changes in Tax Status

Oakville Hydro is a corporation incorporated pursuant to the *Ontario Business Corporations Act* with its head office in the Town of Oakville, Ontario. Oakville Hydro has not had a change in tax status since its last Cost of Service application.

Accounting Orders Requested

Oakville Hydro has no existing Accounting Orders and is not requesting any new Accounting Orders in this proceeding.

Compliance with the Uniform System of Accounts

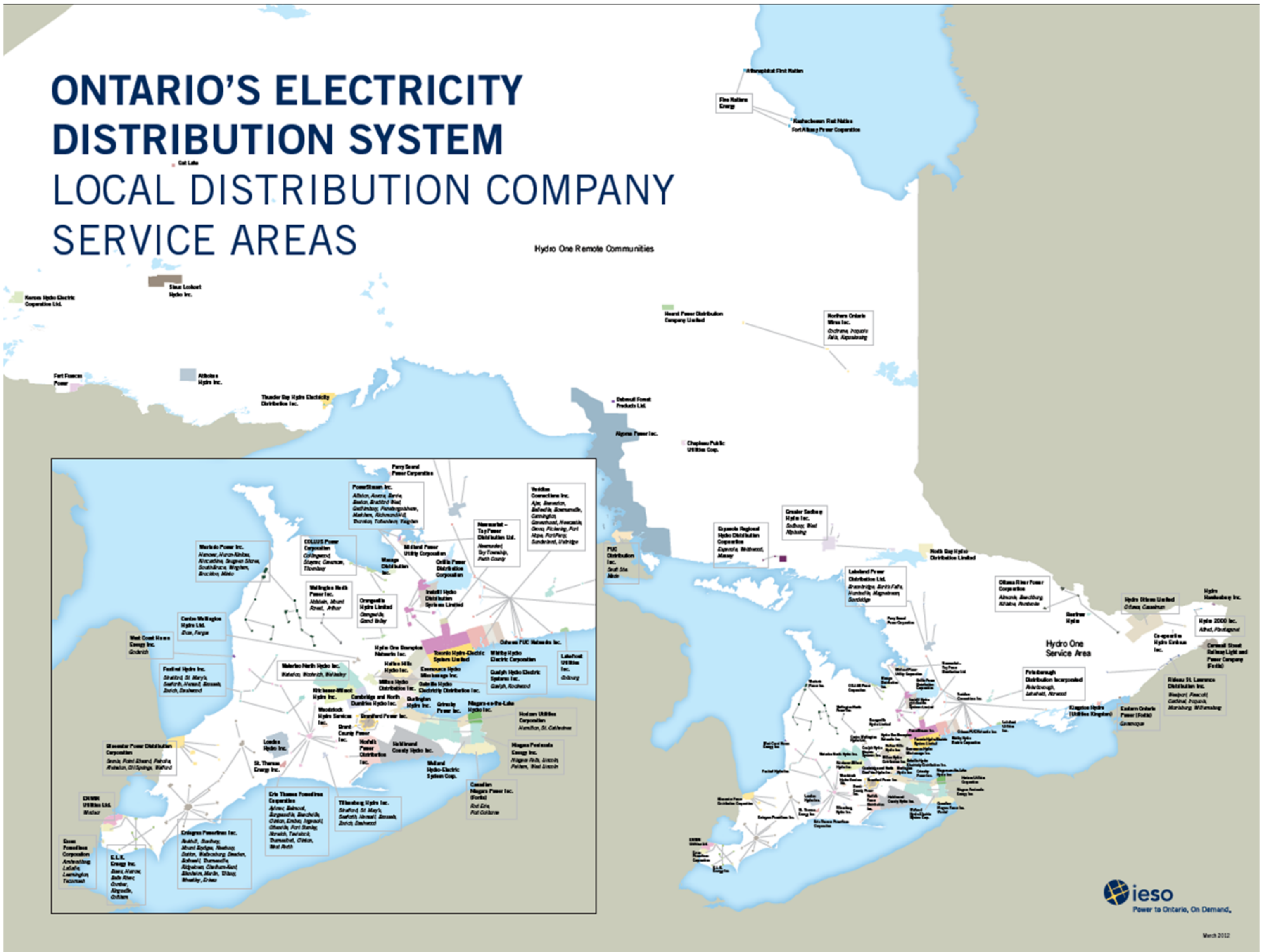
Oakville Hydro has followed the accounting principles and main categories of accounts as stated in the Board's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

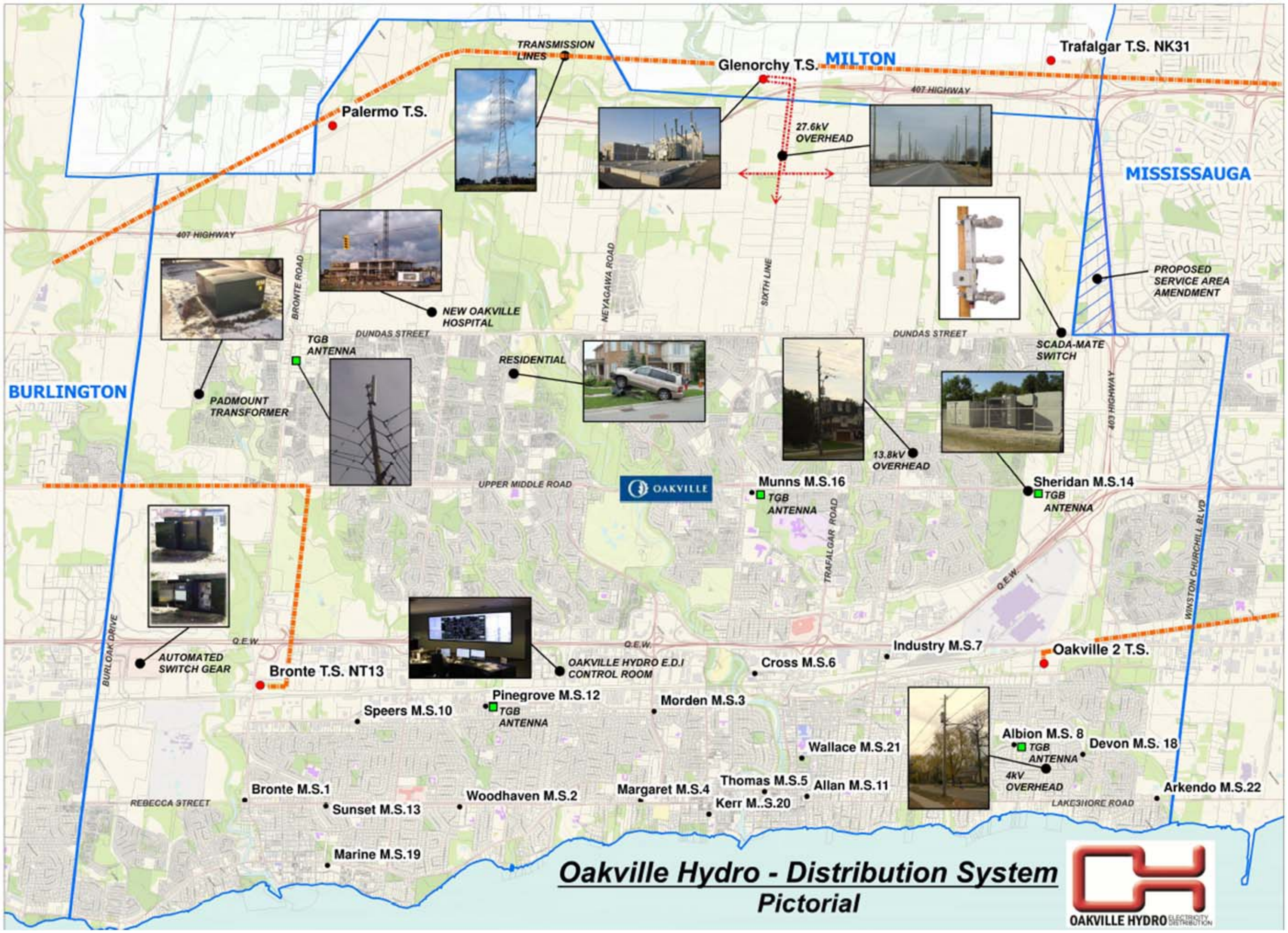
Oakville Hydro's Service Area

General Description:

- Community Served: Town of Oakville
- Total Service Area: 143 Square km
- Urban service area: 104 Square km
- Rural Service Area: 39 Square km
- Distribution Type: Electricity distribution
- Municipal population: Estimated as at December 31, 2012, 184,790

The following maps shows where Oakville Hydro operates within the province of Ontario and the communities that it serves.


ONTARIO'S ELECTRICITY
DISTRIBUTION SYSTEM
LOCAL DISTRIBUTION COMPANY
SERVICE AREAS
Hydro One Remote Communities
Hydro One
Service Area
ieso
Power to Ontario. On Demand.
March 2012


Oakville Hydro - Distribution System
Pictorial
OAKVILLE HYDRO
MILTON
MISSISSAUGA
BURLINGTON
OAKVILLE
TRANSMISSION LINES
Glenorchy T.S.
Trafalgar T.S. NK31
Palermo T.S.
27.6kV OVERHEAD
407 HIGHWAY
PROPOSED SERVICE AREA AMENDMENT
SCADA-MATE SWITCH
NEW OAKVILLE HOSPITAL
PADMOUNT TRANSFORMER
TGB ANTENNA
RESIDENTIAL
13.8kV OVERHEAD
DUNDAS STREET
BRONTE ROAD
NEYAGAWA ROAD
SIXTH LINE
403 HIGHWAY
UPPER MIDDLE ROAD
TRAFALGAR ROAD
WINSTON CHURCHILL BLVD
BURLOAK DRIVE
Q.E.W.
Munns M.S.16
Sheridan M.S.14
AUTOMATED SWITCH GEAR
Bronte T.S. NT13
OAKVILLE HYDRO E.D.I CONTROL ROOM
Cross M.S.6
Industry M.S.7
Oakville 2 T.S.
Pinegrove M.S.12
Speers M.S.10
Morden M.S.3
Wallace M.S.21
Albion M.S. 8
Devon M.S. 18
4kV OVERHEAD
Bronte M.S.1
Sunset M.S.13
Woodhaven M.S.2
Margaret M.S.4
Thomas M.S.5
Kerr M..S.20
Allan M.S.11
Arkendo M.S.22
Marine M.S.19
REBECCA STREET
LAKESHORE ROAD

Explanation of Host and Embedded Utilities

Oakville Hydro's distribution system is directly connected to the transmission system at four Hydro One-owned Transformer Stations: Palermo Transformer Station (230/27.6 kV), Trafalgar Transformer Station (230/27.6 kV), Bronte Transformer Station (115/27.6 kV) and Oakville Transformer Station (230/27.6 kV).

Oakville Hydro is a partially embedded distributor within Hydro One's network. Within the Town of Oakville, Oakville Hydro distributes electricity via 25 feeders at 27.6 kV. Hydro One owns five feeders at Trafalgar Transformer Station and charges Oakville Hydro for transmission (network and transformation connection), and shared low voltage costs.

Oakville Hydro is directly connected to the transmission system at its Glenorchy Municipal Transformer Station (230/27.6 kV) located at 4322 Sixth Line in the Town of Milton. The Glenorchy Municipal Transformer Station is owned and operated by Oakville Hydro.

Effective August 2013, Oakville Hydro became a host utility to Milton Hydro is connected to Oakville Hydro's distribution system at the Glenorchy Municipal Transformer Station located at 4322 Sixth Line in the Town of Milton. Milton Hydro is connected to two of the feeders at the Glenorchy Municipal Transformer Station.

Oakville Hydro is host to a single embedded wholesale consumer who is a wholesale market participant who is connected to Oakville Hydro's distribution system.

List of Neighbouring Utilities

Oakville Hydro is bounded by:

Milton Hydro Distribution Inc.	8069 Lawson Road
	Milton, Ontario, L9T 5C4
	Direct Line: 905-878-3483
	Direct Fax: 905-876-2044

Enersource Corporation	3240 Mavis Road Mississauga, Ontario, L5C 3K1 Direct Line: 905-283-4050 Direct Fax: 905-566-2737
Burlington Hydro Electric Inc.	1340 Brant Street Burlington, Ontario, L7R 3Z7 Direct Line: 905-332-1851 Direct Fax: 905-332-0684

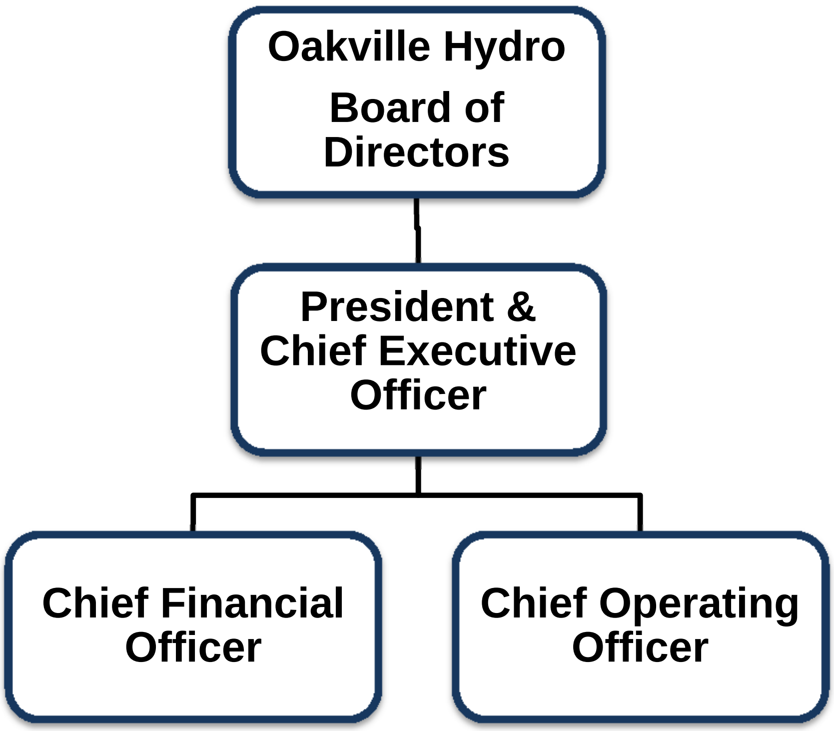
Procedural Orders/Motions/Notices:

On December 11, 2012 the Board issued its list of distributors that are scheduled to apply to have their rates rebased for 2014. Oakville Hydro is one of the twenty distributors listed in Appendix A to that letter. On February 21, 2013, Oakville Hydro confirmed that it intended to submit a Cost of Service Application under the Fourth Generation Incentive Regulation regime for rates effective May 1, 2014.

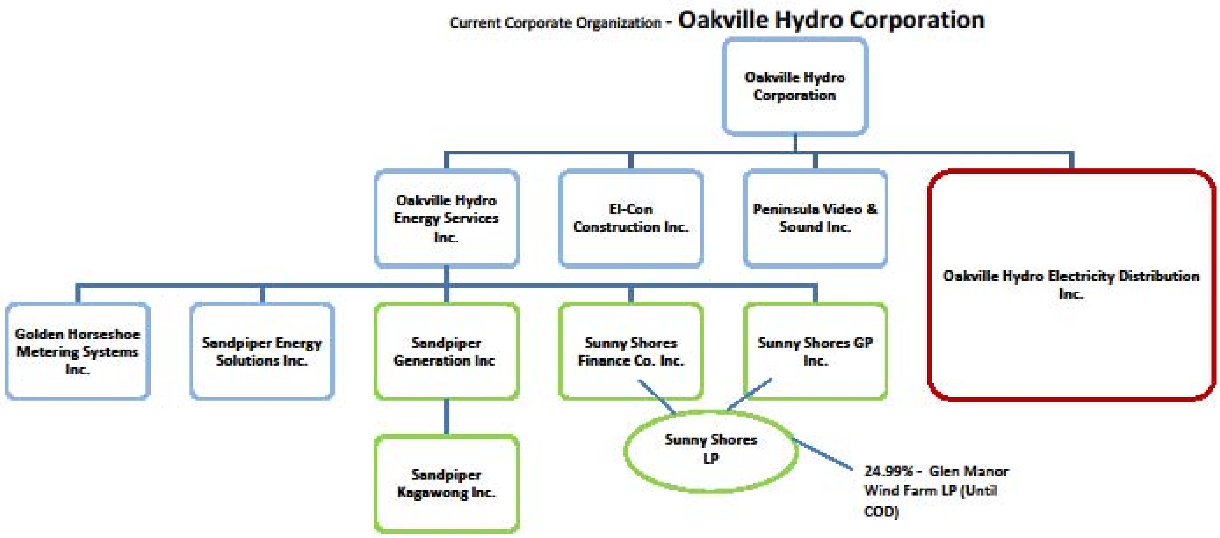
Corporate and Utility Organizational Structure

High-level Utility Organization Chart

Oakville Hydro's high-level organization chart, showing the main units and executive and senior management positions is provided below.



Corporate Entities Chart



Oakville Hydro is a wholly-owned subsidiary of Oakville Hydro Corporation ("OHC") which is 100% owned by the Corporation of the Town of Oakville.

As a trusted utility, Oakville Hydro has been providing electricity distribution and asset management for the residents of Oakville for over 100 years. Oakville Hydro is committed to providing its more than 65,000 residential and business customers, with reliable power supply as well as the best energy and conservation solutions. In cooperation with the Ontario Power Authority, conservation programs at Oakville Hydro include opportunities to save on energy. Through its affiliates, Golden Horseshoe Metering Systems, El-Con Construction Inc., Peninsula Video and Sound Inc., Sandpiper Energy Solutions, Sandpiper Generation Inc., Sandpiper Kagawong Inc. and Oakville Hydro Energy Services Inc., Oakville Hydro Corporation provides customers across southern Ontario with electrical suite metering and meter sealing services, underground utility construction and locating services, as well as rental water heater, geoexchange systems and HVAC solutions. Sandpiper Generation and its subsidiary Sandpiper Kagawong Inc. are also participants in green renewable electricity generation.

The Board of Directors for Oakville Hydro Electricity Distribution Inc. is made up of nine members, three of whom are independent, and the remaining six, are members of the Board of the parent - Oakville Hydro Corporation. The President and CEO of Oakville Hydro Electricity Distribution Inc. reports to the Board of Directors of Oakville Hydro Electricity Distribution Inc.

Oakville Hydro shares goods and services with its affiliates in order to benefit from economies of scale and thereby reduce costs required to provide services to customers. Oakville Hydro is not a virtual utility. The shared services are summarized below. Further detail is provided in Exhibit 4.

The utility provides the following services to affiliates:

- Shared corporate services, including executive management, finance, payroll, and where possible human resources, communications, information technology services, purchasing and warehousing, health, safety and environment; and
- Other services including building occupancy; customer service; all services related to billing including bill printing, mailing, payment processing and collection; and the occasional use of vehicles.

The utility receives the following services from affiliates:

- Corporate governance from the Board of Oakville Hydro Corporation;
- Internal audit services;
- Vehicle maintenance and fueling;
- Tree trimming (line clearing);
- Cable and service locates;
- Meters for residential condominiums converting to individual suite metering, and associated meter installation services;

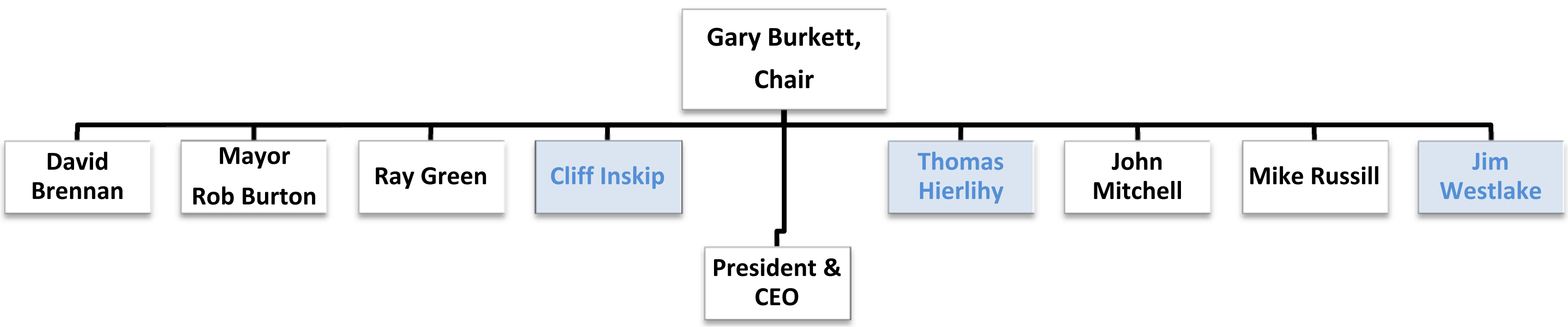
- Asset Condition Assessments;
- Meter sealing, where still required; and
- Civil/underground construction.

Corporate Entities Relationship Chart

Oakville Hydro's company Board of Directors is represented by two Board members that are related to its parent company, the Town of Oakville. Oakville Hydro's President and Chief Executive Officer reports to the Board of Directors. The corporate entities relationship chart is provided on the following page. The independent members of the Board are highlighted in blue.

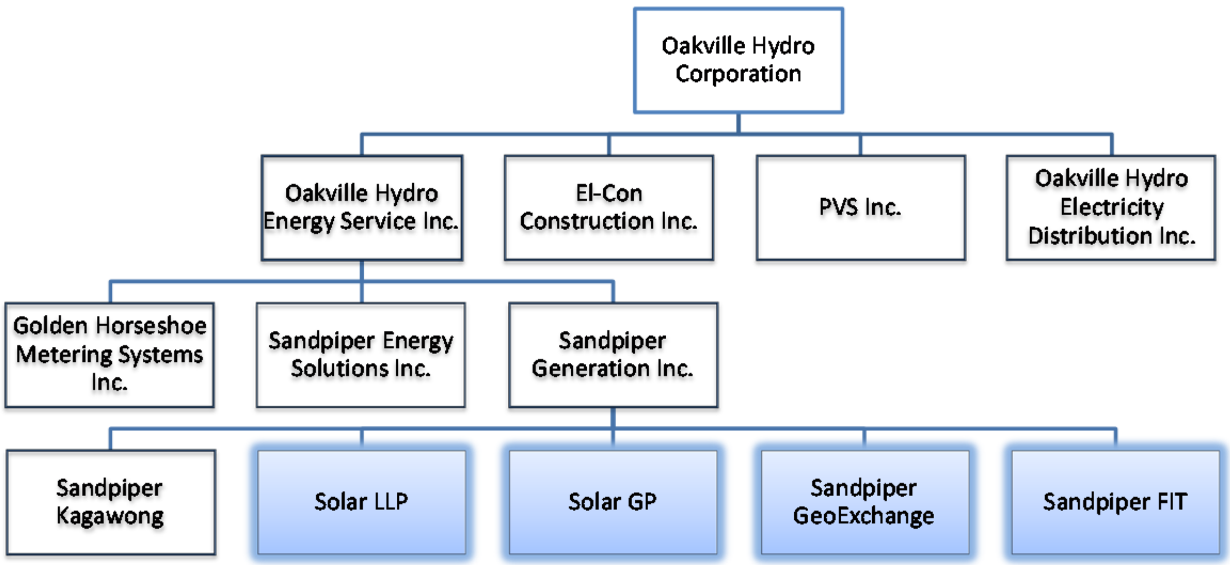
Oakville Hydro Electricity Distribution Inc.

Board of Directors



Planned Changes in Corporate and Operational Structure

Oakville Hydro Corporation's planned changes in Corporate and Operational structure are highlighted in the chart below. The purpose of the planned changes is to provide tax-effective structures and ensure the financial protection across affiliates.



Corporate Governance Practices

As noted above, Oakville Hydro is a wholly owned subsidiary of Oakville Hydro Corporation ("OHC") and the corporate governance structure ties into this corporate structure. The Board of Directors of OHC has governance responsibility for the holding company and all non-regulated subsidiaries. The Board of Directors of Oakville Hydro Electricity Distribution Inc. (the "Oakville Hydro Board") has direct responsibility for the governance of Oakville Hydro. Both Boards are active and diligent in their role of oversight and monitoring and believe in the importance of excellence in corporate governance. Both Boards regularly review and adopt, where appropriate, best practices in corporate governance.

1. Oakville Hydro Board of Directors

Oakville Hydro has nine corporate independent board members (i.e., board members are not the Employees/Officers / Management of Oakville Hydro). The Oakville Hydro Board conforms to the Affiliate Relationships Code ("ARC") with one-third of its directors independent from Affiliates.

The Oakville Hydro Board members consist of individuals with a variety of professional backgrounds. Their biographies are provided below. Board members of Oakville Hydro are recruited and selected based on an established skills matrix. The skills matrix describes the desired skills and attributes including:

- business experience;
- experience on boards of significant corporations;
- financial, legal, accounting and/or marketing experience;
- industry knowledge
- knowledge of public policy and government regulation issues relating to the business and the electricity industry;
- knowledge and experience with risk management strategy and corporate governance;
- knowledge and experience concerning environmental matters, labour relations and occupational health and safety.

In addition, preference would be given to qualified candidates who are residents of Oakville.

Open and frank discussions are encouraged at all Board and Committee meetings. Management provides the Oakville Hydro Board with all the necessary information (e.g., written reports and submissions, oral presentations, and verbal or written responses to Oakville Hydro Board inquiries) in relation to all matters which require Oakville Hydro's Board input and/or approval. The Oakville Hydro Board conducts an annual self-assessment of its overall performance as well as individual member's performance.

All of the processes followed by the Oakville Hydro Board are aligned with the Oakville Hydro Board adopted Mandates and Charters. The Board Members' biographies are provided below.

Gary Burkett is the Board Chair of Oakville Hydro Corporation. He is a senior Human Resources executive with over thirty eight years' experience with three blue chip corporations: Molson Breweries, Bell Canada and Federal Express Canada. Gary's HR subject matter expertise is anchored in business acumen with having been President Molson Saskatchewan Breweries together with having served on six commercial Boards and four volunteer Boards.

Gary is presently Managing Director Human Resources with Federal Express Canada and serves on the Oakville Hydro Board and the George Brown College School of Business Advisory Board.

Gary has lived and worked in western, central and eastern Canada and moved to Oakville in 1986. He and his wife have four children.

David Brennan is a Director of Oakville Hydro Corporation and Chair of Governance and Risk Committee. He is a proven senior executive with extensive background in legal and general management. As General Counsel or General Manager, he has been successful in combining legal and business knowledge with superior team building skills to generate significant bottom-line contribution and results. David is known as a strategic, pragmatic thinker with deep corporate and commercial acumen and an ability to drive profitable growth and stakeholder satisfaction. He is recognized for strong leadership and the vision to implement long and short term strategies, meeting both current and evolving business needs.

Over the last twenty years, David has held the executive General Counsel position at General Electric Canada and Ontario Power Generation where he led legal teams in excess of 40 people. Under his leadership, these teams have successfully dealt with all legal and compliance matters and completed transactions and projects with values in excess of a billion dollars. As well, during this period, he held General Manager/COO positions at GE Capital Canada and Miller

Thomson where he had P&L responsibility including marketing, HR, IT, finance, operations, customer service and collections. David's areas of legal expertise include financial services, energy, first nations/metis, infrastructure, employment, and mergers and acquisitions.

In addition to professional development at Harvard and Wharton business schools, David holds a Bachelor of Laws degree from the University of Western Ontario and a Bachelor of Business Administration from Wilfrid Laurier University. David is also admitted to the Ontario and Alberta Bars.

Mayor Rob Burton has been a Board member of Oakville Hydro Corporation since 2006. He is member of Finance and Audit Committee, Governance and Risk Committee and Human Resources Committee.

Mayor Burton won re-election to a second term as Oakville's Mayor in 2010 in a landslide win that gave him a strong mandate to continue to control growth, debt and taxes, protect green space and the environment, catch up on Oakville's needs for community facilities, and create in Oakville Canada's most livable town. Prior to running for public office, Mayor Burton had a successful career as a businessman, director and producer in journalism, film and television. He is best known for starting YTV. During his time as Mayor, several ground breaking initiatives that protect Halton and Oakville's ability to control the built and natural environment and the health, safety and finances of the community have been implemented. These include the Oakville and Halton Natural Heritage Systems (2007/10), performance-based program budgeting or PB2 (2007), the Private Tree Protection By-law (2008), the Town Energy Management Plan (2009), the Health Protection Air Quality By-law (2010), and the new official plans Livable Oakville (2009) and Sustainable Halton (2010).

Mayor Burton co-founded and co-chairs the Municipal Leaders for the Greenbelt. Environmental Defence Canada calls him the greenest mayor in Canada. His 1971 Masters of Science degree thesis at Columbia University statistically linked the effects of air pollution on illness and pre-mature death. Mayor Burton also serves on the boards of Halton Healthcare Services, Halton Children's Aid Society, Halton Community Housing Corporation, Halton Regional Police

Services, and Tree Canada. He avidly supports Oakville's sports, arts and culture groups and charities.

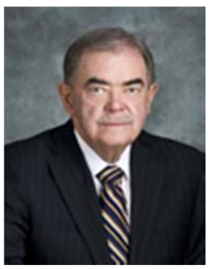
Ray Green is a Director of Oakville Hydro Corporation and a member of Finance and Audit Committee. He is the Chief Administrative Officer of the Town of Oakville. A 30-year veteran with the Town, Mr. Green has held a number of senior positions prior to his role as CAO, including Commissioner of Infrastructure and Transportation Services, Commissioner of Community Services, Director of Public Works and Assistant Director, Operations.

Mr.Green is a Professional Engineer with a B.A.Sc., (Civil Engineering), from the University of Toronto.

Thomas G. Hierlihy is an Independent Director of OHEDI and a member of the Finance and Audit Committee, Governance and Risk Committee and Human Resources Committee. He retired from KPMG LLP after forty years, thirty-one of which were as a Partner. As a Chartered Accountant, he focused on taxation issues in both the business world and as a lecturer. Mr. Hierlihy's community experience includes being the treasurer and a board member of both the United Way and the Community Foundation of Oakville.

Cliff Inskip is an Independent Director of OHEDI and a member of Governance and Risk Committee. He is Managing Director - Head of Infrastructure & Project Finance, Debt Capital Markets at CIBC World Markets. He leads a team that provides financial advisory and bond underwriting services to government and corporate clients involved in infrastructure development. Cliff has advised developers on multi-billion dollar projects in the power, energy and pipeline sectors and has also advised numerous electricity distribution utilities on financing related matters. Cliff has appeared as an expert witness before the National Energy Board and the Standing Senate Committee on National Finance. He is a frequent conference speaker and university guest lecturer on infrastructure financing and public private partnerships.

Cliff graduated from UBC with a B.A.Sc. in Civil Engineering and an MBA and also attended an International Banking Summer School program at Cambridge University. Cliff is a member of Professional Engineers Ontario and was named a TopGun Banker by Brendan Wood International. He is a Chartered Director and previously served on the board of CIBC Bank Plc.



John K. Mitchell is a Director of Oakville Hydro Corporation and a Chair of Finance and Audit Committee and a member of Human Resources Committee. He received a Bachelor of Commerce from the University of the Witwatersrand in South Africa and qualified as a Chartered Accountant in Canada, England and Wales and South Africa. His work experience includes many years as Senior Vice President Finance and Chief Accountant of Scotiabank and Board member of several of their various operating subsidiaries in Canada, Nassau and Barbados. He remains on the Board of the Scotiabank subsidiary company in Barbados where he was previously Managing Director of their worldwide reinsurance operations for several years. Prior to coming to Canada he was General Manager of the Industrial Development Corporation of South Africa where he oversaw international capital projects throughout the world. In 2001 he was awarded a fellowship of the Institute of Chartered Accountants in Ontario.

Mike Russill is a Director of Oakville Hydro Corporation and Chair of Human Resources Committee. He joined WWF-Canada as President and CEO in 2004. Under his leadership WWF Canada increased its revenues by nearly 90% and has broadened its conservation reach into Climate Change and Freshwater. Mike spent thirty-years in the private energy sector, with Shell Canada Inc., Petro-Canada Inc. and Suncor Inc. At Suncor he held several Vice-President assignments; Strategic Integration, Business Services (finance, HR and administration), and Retail. Mike served as Executive Chairman of Aadco Automotive, an environmentally focused automotive recycling company, and the first to receive Canada's Eco logo. He has served as a Director on a number of Boards including Nature Conservancy of Canada, CS Able Ltd. USA, Pioneer

Petroleum Limited, UPI Petroleum. Mike is past Chairman of the Atlantic Petroleum Association, and the Ontario Region of the Canadian Petroleum Products Institute.

He is a member of the Advisory Boards of the School Of Management at Dalhousie University, Green living Enterprises and Sustainable Prosperity. Mike is a frequent speaker on Business and Sustainability.

He graduated from Ryerson in Business Administration and completed the Western Executive Program and the University of Michigan Human Resources Executive Program. Mike is married to Karen and they have three grown children. His interests include spending time at the family cottage, hiking, kayaking, canoeing and golfing.

Jim Westlake is an Independent Director of OHEDI and a member of Human Resources Committee. He is a retired bank executive with more than 35 years in the financial services industry, most recently as Group Head, International Banking and Insurance, Royal Bank of Canada and a member of the bank's Group Executive one of nine executives responsible for setting the overall strategic direction of RBC.

Before joining RBC in January 1995, Mr. Westlake spent 19 years with the Metropolitan Life Insurance Company, most recently as vice-president and chief operating officer of Canadian operations.

Mr. Westlake has a long history of service to community and charitable organizations including hospitals, universities and children's associations. Activities of note include serving as Chair of the Canadian Chamber of Commerce and General Campaign Chair of the United Way of Peel Region. Mr. Westlake was the recipient of the Queen's Golden Jubilee medal for community service.

He is also on the boards of the Canadian Paralympic Committee and the International Insurance Society.

Born in Kingston, Ontario, Mr. Westlake graduated with a diploma in business administration from Loyalist College in Belleville and a Master of Business Administration degree from Queen's University.

2. Board Mandate

The Board has adopted a Mandate in November 2010, which is reviewed annually revised as required. The most recent Mandate for the Board of Directors is provide as Appendix D to this Exhibit.

3. Board meetings

The Board meets quarterly with Committees of the Board prior to the scheduled Board meeting. Board and Committee meetings are scheduled in advance and attached is a schedule of Oakville Hydro Board meetings for 2013. In addition, non-scheduled Board or Committee meetings are held to discuss pertinent issues arising outside of the normal scheduled meetings. The 2013 calendar of events is provided below.

2013 CALENDAR OF EVENTS

All meeting(s) start at 7:30 am unless otherwise stated

All underlined dates indicate a new listing or a revision.

February 27 – Wednesday GRC meeting
March 4 - Monday Town Council Meeting – Quarterly update – 7:00 pm
March 6 - Wednesday HRC meeting
March 22 - Friday FAC meeting
April 4 - Thursday Board meeting
May 4 - Saturday Board Strategic Retreat – Full day – 8:00 am
May 27 - Monday Town Council Meeting – Quarterly update / Annual General Meeting – 7:00 pm
May 29 - Wednesday GRC meeting
June 4 - Tuesday HRC meeting
June 6 - Thursday FAC meeting
June 20 - Thursday Board meeting
September 11 - Wednesday GRC meeting
September 17 - Tuesday HRC meeting
September 19 – Thursday FAC meeting
October 3 - Thursday Board meeting
October 7 - Monday Town Council Meeting – Quarterly update – 7:00 pm
November 2 – Saturday Board Education Retreat – Full day – 8:00 am
November 7 – Thursday FAC meeting – Audit Planning with KPMG
November 13 – Wednesday GRC meeting
November 19 - Tuesday HRC meeting
November 21 - Thursday FAC meeting
December 9 – Monday Town Council Meeting – Quarterly update – 7:00 pm
December 12 – Thursday Board meeting

GRC = Governance and Risk Committee
HRC = Human Resources Committee
FAC = Finance and Audit Committee

4. Orientation and Continuing Education

As part of orientation, new Directors receive written materials including, but not limited to, Oakville Hydro's By-law, Board Mandate and Charter, Committee Mandates, Chair position description, and financial statements. The orientation process follows a March 29, 2012 documented process, although it is subject to change depending on additional information available or in response to queries from the new Director. A copy of the Board Orientation Process is provided as Appendix E in this Exhibit. As noted in the process, new Directors attend meetings with the Chair of the Board, the Chief Executive Officer as well as management or other individuals as appropriate.

All Board members are provided access to previous Board and Committee meeting presentations and submissions as well as minutes, financial statements, action registers and contact information.

Directors participate in a Board of Directors Education Retreat conducted once a year. This is normally a one day session which provide the Board of Directors with updates and information about the Corporation's business, governance and industry through Management or third party presentations. Subject matter experts are retained to provide presentations and insight on current developments and topics relevant to the industry.

By way of background, the Board of Directors has had the following topics and presenters in the past:

Topics and presentations from management:

- **April 17, 2010**
  - Corporate Governance, Trends and Leading practices – Neil Brown, Deloitte LLP
  - Board Effectiveness – Frank Arnone, Blakes Cassels & Graydon LLP

- **November 5, 2011**
  - Regulatory Rate Setting Model – Bruce Bacon, Borden Ladner Gervais LLP
  - Risk Management – Dr. Chris Bart, Bart and Company Inc.
  - IFRS Conversion – Lois Ouellette, KPMG LLP
  - Customer Centricity – Sid Ridgley, Simul Corp.

- **May 5, 2012**
  - Risk Tolerance / Appetite
  - Merger/Acquisitions/Divestitures
  - Sustainability
  - Environmental and Landscape Developments
  - Benchmarking

- **November 3, 2012**
  - OPA Power System Planning – Amir Shalaby, OPA
  - Renewed Regulatory Framework – Aleck Dadson, OEB
  - Electricity Distribution in Oakville
  - Control Room Tour
  - Glenorchy Municipal Transformer Station – November 3, 2012

- **May 4, 2013**
  - Sustainability
  - Environmental and Landscape Developments
  - Benchmarking
  - Consolidation of Local Distribution Companies
  - Strategic Opportunities in a converging sector
  - Outage Management

In addition, Directors are provided tours of the distribution system to better understand business, industry or any latest industry-related developments. The Board of Directors participated in a tour of the Glenorchy Municipal Transformer Station, built in 2011 and a tour of Oakville Hydro's 24/7 control room, including a discussion with the Control Room operators. These tours are often incorporated into new Director orientation.

The Directors are also provided with weekly newspaper clippings of relevant industry news and monthly Governance newsletters as well as monthly Management update reports.

Directors are also encouraged to take professional development courses, such as Directors College courses with a cost sharing mechanism according to Board approved Directors' Education program.

5. Ethical Business conduct

The Board has adopted a Code of Conduct for Directors, Officers and Employees. All Directors, Officers and Employees are required to read and sign their respective codes of conduct annually. Copies of the Codes of Conduct are provided as Appendix F. In addition, Directors sign a disclosure questionnaire annually to identify any conflicts of interest. Potential conflicts of interest are assessed at the outset of all Committee and Board meetings.

A telephone hotline and web reporting service is made available for any employee to anonymously report an issue or issues that could potentially violate the Oakville Hydro Code of Conduct including:

- accounting and auditing matters
- conflicts of interest
- customer relations issues
- discriminations or harassment
- employee misconduct or inappropriate behavior
- fraud or theft
- improper use of intellectual property
- privacy

- safety
- substance abuse
- workplace violence
- other concerns worthy investigation

If there is a report of an incident though the third party web or hotline, notification is forwarded to the Vice President Customer Services and Organizational Development who is obligated to report to the Human Resources Committee and the Finance and Audit Committee and ultimately report to the Board.

6. Nomination of Directors

The Board has established an Advisory and Nominating Committee and one of its responsibilities is to identify new candidates for Oakville Hydro Board nomination. This Committee along with other Board members and the Shareholder develop a list of candidates through contacts of existing Oakville Hydro Board of Directors, recruitment agencies or advertisement in the local newspaper for consideration for appointment to the Oakville Hydro Board, if and when required. After considering the competencies and skills that existing Directors possess and those that the potential new candidate should bring to the Oakville Hydro Board, the Committee identifies candidates qualified for Board membership makes a recommendation to the Shareholder.

The Board skills matrix is updated regularly with the skill of the new Director.

Board Committees

The following is a list of Board core Committees:

- Finance and Audit Committee
- Human Resources Committee
- Governance and Risk Committee

The Board Committees members are selected from both the Oakville Hydro Board and the OHC Board, although outside non-director members are possible. The Committees adopted written mandates in late 2010 or early 2011 which are reviewed annually and revised if necessary.

- Finance and Audit Committee:

  The Finance and Audit Committee's mission is to assist the Board in fulfilling its obligations by overseeing and monitoring Oakville Hydro's financial accounting and reporting and the external audit process.

- Human Resources Committee

  The Human Resources Committee's mission is to assist the Board in succession planning, performance management plan, compensation and benefit programs, the human resource strategic planning and policies and the organizational development plan and additional mandate for the responsibility for customer service levels.

- Governance and Risk Committee

  The Governance and Risk Committee's mission is to assist the Board with respect to governance, risk and related matters and make recommendations to the Board relating to these matters.

The Mandate and Charter of the above Committees are provided as Appendix G in this Exhibit.

The Committee members are appointed by the Oakville Hydro Board and expected to be independent from Oakville Hydro Corporation and its subsidiaries. The Finance and Audit Committee members are required to be financially literate. The Committees have the ability and authority to engage external experts to assist them in conducting their fiduciary duty, subject to notice and approval by the Oakville Hydro Board.

Transmission Assets

In its Decision and Order in Oakville Hydro's 2011 IRM application for an order or orders approving or fixing just and reasonable distribution rates and other charges, EB-2010-0104, the Board approved Oakville Hydro's request to have its newly constructed municipal transformer station to be a distribution asset pursuant to section 84(a) of the *Ontario Energy Board Act, 1998*. Oakville Hydro is not seeking approval to have any additional transmission assets deemed as distribution assets in this Application.

Accounting Standard

In accordance with the Board's letter issued July 17, 2012 entitled *Regulatory Accounting Policy Direction Regarding Changes to Depreciation and Capitalization Policies in 2012 and 2013*, this Application has been prepared using CGAAP with the new depreciation rates and capitalization policies (New CGAAP). In accordance with the Filing Requirements, Oakville Hydro has provided information for the historic years 2010, 2011 and 2012 in CGAAP, the 2013 Bridge Year CGAAP and New CGAAP and 2014 Test Year in New CGAAP.

The change in depreciation rates and capitalization policies has impacted the calculation of the cost of self-constructed capital assets, depreciation rates, and operating expenses. These changes have impacted the 2014 rate base and the 2014 distribution revenue requirement. Oakville Hydro has provided detailed explanations of these changes in the applicable section of the Application.

Deviations from the Filing Requirements

Oakville Hydro has not, to the best of its knowledge, deviated from Chapter 2 of the Board's Filing Requirements for Electricity Distribution Rate Applications, issued July 17, 2013 and Chapter 5 of the Board's *Filing Requirements for Electricity Distribution Rate Applications*, issued March 28, 2013.

Changes to Methodologies

Oakville Hydro has not made any changes to the methodologies used in previous applications. However, Oakville Hydro's Application has amended its depreciation rates and capitalization policy.

Oakville Hydro is requesting changes to its depreciation rates and capitalization policy in its Application. The following provides a summary of the rationale behind the changes requested. Specific details on the changes are provided in Exhibit 2.

In February 2013, the Accounting Standards Board (the "AcSB") announced a deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities to January 1, 2015, after three previous one-year deferrals. The decision to extend the deferral date to January 1, 2015 was made in light of the continued uncertainty surrounding the treatment of regulatory accounts. Discussions at the International Accounting Standards Board (the "IASB") indicate that it expects to issue an interim standard on regulatory accounting by the end of the 2014.

On April 30, 2012, the Board issued a letter entitled "*Impact of the Decision to Defer the Mandatory Date for the Implementation of International Financial Reporting Standards to January 1, 2013 by the Canadian Accounting Standards Board"*). The Board provided guidance for all electricity utilities regarding the impact of the decision by AcSB to defer the mandatory changeover to IFRS to January 1, 2013. In its letter, the Board clarified that it would not require regulatory accounting and reporting for 2012 to be in MIFRS if a distributor is not required to adopt IFRS for financial reporting and opts to remain on CGAAP.

However, on July 17, 2012, the Board issued a letter entitled *Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013*. In its letter, the Board provided direction on the option to defer IFRS changeover in 2012. The Board advised distributors that changes to depreciation rates and capitalization policies that would have been implemented under IFRS could be made in 2012 under CGAAP (i.e. effective

January 1, 2012), and must be made no later than 2013 (i.e. effective January 1, 2013), regardless of whether the AcSB permits further deferrals beyond 2012 for the changeover to IFRS.

Oakville Hydro has elected to continue to prepare its financial statements under CGAAP. In accordance with the Board's guidelines published July 17, 2012, Oakville Hydro has implemented changes to its depreciation rates and capitalization policy effective January 1, 2013. These CGAAP statements, prepared using the new depreciation rates and capitalization policy will be referred to as New CGAAP.

Changes to Depreciation Rates

Under IFRS, specifically under International Accounting Standard ("IAS") 16, each significant part of an item of Property Plant and Equipment ("PP&E") must be depreciated separately. This is referred to as component accounting. The rationale for component accounting is that since not all components of an item of PP&E have the same useful life, they will depreciate at different rates. The Board requested that utilities have third party analysis to support the development of components and useful lives.

Consequently, in 2009, in preparation for the original (before deferral) conversion to IFRS, Oakville Hydro contracted Kinectrics to perform an analysis of the useful lives of its distribution assets in conjunction with Enersource Corporation, Milton Hydro Distribution Inc., Burlington Hydro Electric Inc., and Halton Hills Hydro Inc. Subsequent to Oakville Hydro's review and analysis the Board commissioned Kinectrics to perform an industry-wide review. This report was received December 10, 2009. More details on this process are provided in Exhibit 2.

Based on these Kinectrics reports, Oakville Hydro broke down its PP&E into 39 components. Oakville Hydro's components and useful lives are set out in Table 1-17.

Table 1-17: Oakville Hydro's Components and Useful Lives

OEB Code	Description	Old CGAAP Useful Life	Kinectrics Range (Board Report)	Kinectrics Typical Useful Life (Board Report)	New CGAAP Useful Life
1830	OH Pole System	25	35-75	45	45
1835	OH Devices	25	30-60	45	45
1835	OH Local Motorized/Remote Automated Switches	25	15-25	20-25	25
1835	OH Wires	25	50-75	60	60
1850	Distribution Transformers	25	25-60	35-40	35
1840	Duct & Civil ex Metal	25	30-85	50-60	50
1840	Metal Frames & Covers	25	20-45	30	30
1845	Pad Mounted Switch Gear	25	20-45	30	30
1845	UG Cable System	25	25-55	30-40	35
1820	Substation Equipment	30	10-65	20-55	25
1820	MS Main Switch Gear	30	30-60	40-50	55
1850	MS Transformers	25	30-60	45	45
1980	System Supervisory Equipment	15	10-65	20-45	15
1820	TS Substation Equipment	25	10-65	20-55	30
1820	TS Switchgear	25	30-60	40-50	50
1815	TS Transformer	50	30-60	45	45
1860	Meters	25	15-35	n/a	25
1860	Smart Meters	25	5-15	n/a	10
1860	Smart Meters - Infrastructure	25	10-20	n/a	10
1855	UG Services - Duct & Civil	25	30-85	50-60	50
1855	UG Services - Cable	25	25-60	35-40	35
1920	Computer Hardware - PCs	3	3-5	n/a	3
1920	Computer Hardware - Servers	3	3-5	n/a	4
1920	Computer Hardware - Infrastructure	3	3-5	n/a	4
1925	Computer Software - Client	5	2-5	n/a	4
1925	Computer Software - Infrastructure	5	2-5	n/a	4
1925	Computer Software - Business Apps	4-5	2-5	n/a	5
1915	Office equipment	10	5-15	n/a	10
1960	Safety Equipment	10	5-10	n/a	10
1808	Buildings	60	50-75	n/a	60
2005	Capital Lease - Building	Life of lease	n/a	n/a	Life of lease
1805	Land	n/a	n/a	n/a	n/a
1810	Leasehold Improvements	10	n/a	n/a	10
1935	Warehouse Equipment	10	5-10	n/a	10
1940	Major Tools	10	5-10	n/a	7
1930	Vehicles - Passenger	5-8	5-10	n/a	5
1930	Vehicles - Light & Heavy	5-8	5-15	n/a	10
1930	Vehicles - Other Mobile Equipment	5	5-20	n/a	10
1970	Load Management	15	20	20	20

Oakville Hydro reclassified its capital assets to the new components effective January 1, 2010. However, as previously noted, due to the deferral of the implementation of IFRS, new useful lives were not applied to the new components until January 1, 2013, as required by the Board.

The impact of the change to depreciation rates is a decrease in depreciation expense and accumulated amortization of $3,541,709 in 2013 and $3,567,391 respectively in 2014 as compared to the previous depreciation expense under Old CGAAP.

Changes to Capitalization Policy

Under IFRS, specifically IAS 16, the cost of an item of PP&E includes only those costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 16 does not define the term "directly attributable". The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E. Where CGAAP allows for the capitalization of training and general and administrative overhead, IFRS does not.

Under Old CGAAP, prior to the change in estimates, in addition to purchase price, direct construction and direct development costs, Oakville Hydro included employee salaries and benefits and an allocation of overhead costs attributable to the asset in determining the cost of an item of PP&E. These overhead costs were capitalized to PP&E by applying a predetermined rate (burden rate) to the direct costs. Burden rates are based on the cost expected to be incurred and vary by type of overhead cost.

As part of the transition to IFRS, Oakville Hydro has reviewed its overhead costs to determine which continue to be appropriate directly attributable expenses to capitalize and which should be expensed as part of OM&A in accordance with IAS 16. Oakville Hydro determined the following burdens are directly attributable to PP&E and should therefore be capitalized:

Labour burden - for IFRS this burden rate will consist of a direct benefit burden only and will be reduced from 108% to 30% to reflect the removal of the following:

- apprenticeship training and non-productive time which cannot be directly attributed to a specific job
- administration burden of 50%, which recovered management time and General and Administrative costs of Engineering and Operations

The New CGAAP benefit burden of 30% recovers the benefits that employees are entitled to receive such as CPP, EI, medical and dental benefits, OMERS, EHT and WSIB. This burden is applied to hourly labour cost by specific job at 30% and is therefore directly attributable to an item of PP&E at the time the cost is incurred.

Vehicle Charges – with respect to repairs and maintenance, IFRS states that the costs of day-to-day servicing of an item of PP&E cannot be recognized in the carrying amount. These costs are expensed as incurred. Therefore the vehicle charge to capital will only include fuel and consumables.

Table 1-18 below provides a summary of the change in burden rates from Old CGAAP to New CGAAP. Capitalization of overhead and burdens are discussed in more detail in Exhibit 2, Tab 6.

Table 1-18: Summary of Changes to Burdens

Burden	Old CGAAP	New CGAAP
Labour	108% of hourly cost Direct benefits 22% (CPP, EI, dental, medical, OMERS, EHT, WSIB) Unproductive time 36% (training, weather, vacation, bereavement time, sick time, union business etc.) Administration burden (50%) (Line Supervisor, P&C and engineering for oversight and project coordination)	30% of hourly cost Direct benefit 30% (CPP, EI, dental, medical, OMERS, EHT, WSIB)
Direct materials	5% charge to cover purchasing and payment processing	Nil
Subcontractors	15% charge to cover purchasing, and payment processing and engineering and supervision of capital projects	Nil
Warehouse	18% charge to cover purchasing and payment processing, storage costs and warehouse operations	Nil
Vehicles	Hourly rate based on an allocation of maintenance costs, fuel and consumables and depreciation of equipment	Hourly rate to include only fuel and consumables

Oakville Hydro's new capitalization policy was not effective until January 1st, 2013, as required by the Board. As a result of the changes to the capitalization policy, Oakville Hydro has identified a total of $3,313,991 for 2013 and $3,127,697 for 2014, which was included in capital additions under Old CGAAP which is not directly attributable to PP&E under new CGAAP and therefore cannot be capitalized.

Of the $3,313,991 in 2013 which cannot be capitalized, $2,962,133 will be expensed in 2013. The remaining $351,857 relates to burdens associated with the closing of work-in progress. These burdens were incurred in 2012 and therefore cannot be expensed in 2013.

Of the $3,127,697 in 2014 which cannot be capitalized, $3,027,884 will be expensed in 2014. The remaining $99,814 relates to burdens associated with the closing of work-in progress. These burdens were incurred in 2012 and therefore cannot be expensed in 2014.

Impact on Account 1576 – Accounting Changes

Pursuant to the directives and guidance provided in the revised Accounting Procedures Handbook, Oakville Hydro has created a new deferral account to capture the difference in PP&E as a result of the accounting changes to depreciation expense and capitalization policies mandated by the Board in 2013.

Since Oakville Hydro is not planning to transition to IFRS until January 1st, 2015, it is using Account 1576 - Accounting Changes under CGAAP to record the required accounting changes in relation to depreciation expense and capitalization policies in 2013.

As detailed in Table 1-19, these accounting changes result in an increase in the 2013 Total PP&E of $127,904. This represents:

- A decrease of $3,313,991 due to the change in capitalization policies on 2013 additions (in rate base)
- An increase of $3,541,709 due to the change in depreciation rates (in rate base)
- A decrease of $99,814 decrease due to the change in capitalization policies on 2013 WIP (not in rate base)

Table 1-19 - Impact of Accounting Changes – Total PP&E

Description	2013 Bridge Year - Old CGAAP	2013 Bridge Year - New CGAAP	Variance Old CGAAP vs. New CGAAP
Reporting Basis	CGAAP	CGAAP	CGAAP
PP&E			
Gross Fixed Assets - Rate Base	$272,757,460	$269,443,469	-$3,313,991
Accumulated Depreciation	117,923,717	114,382,008	-3,541,709
Total PP&E before WIP, as per 2-BA1	**$154,833,743**	**$155,061,461**	**$227,718**
Work In Progress	415,121	315,307	-99,814
Total PP&E including WIP	**$155,248,864**	**$155,376,768**	**$127,904**

In accordance with the Board’s letter issued July, 2012, Oakville Hydro has calculated a rate of return component to be applied to the balance in Account 1576 in Table 1-20. The balance of $135,541 represents the total amount owing to customers. Oakville Hydro proposes a one year disposition period in order to return this amount to the customer as soon as possible. This disposition is discussed further in Exhibit 2, Tab 6.

Table 1-20: Calculation of Account 1576 Rate Rider

Description		Calculation	Total
2013 Closing Balance PP&E Old CGAAP		A	$155,248,864
2014 Closing Balance PP&E New CGAAP		B	$155,376,768
Closing Balance in Account 1576		C = A - B	-$127,904
WACC		D	5.97%
Return on Rate Base Associated with Account 1576 balance at WACC	per year	E = C * D	-$7,637
Disposition Period		F	1
Return on Rate Base Associated with Account 1576 balance at WACC	total	G = E * F	-$7,637
Amount included in Account 1576 Rate Rider Calculation		**H = C + G**	**($135,541)**

Impact on Net Income

The impact on net income of the change to Oakville Hydro's depreciation rates and capitalization policy is summarized in Table 1-21. The decrease in depreciation expense is partially offset by an increase in expenses as burdens previously capitalized under old CGAAP are expensed under New CGAAP. 2013 and 2014 Net Income before Tax is $579,575 and $539,507 higher under New CGAAP, respectively.

Table 1-21: Summary of Changes to Net Income

Description	2013 Old CGAAP vs. New CGAAP	2014 Old CGAAP vs. New CGAAP	Comments
Gross Fixed Assets - Excluding WIP Additions	$ (2,962,133)	$ (3,027,884)	Reduction to Gross Assets due to disallowed burdens incurred in 2013
2013 Additions from 2012 WIP	(351,857)	(99,814)	Disallowed burdens incurred in 2012; cannot be moved to 2013 expense but are included in 1576
Total Gross Fixed Assets - Rate Base	**$(3,313,991)**	**$(3,127,697)**	
Accumulated Depreciation	(3,541,709)	(3,567,391)	Decrease in depreciation as useful lives extended under New CGAAP
Net Book Value - Rate Base	**$ 227,718**	**$ 439,694**	
OM&A Expense	$ 2,962,133	$ 3,027,884	Only disallowed burdens incurred in 2013 can be moved to expense
Depreciation Expense	(3,541,709)	(3,567,391)	Decrease in depreciation as useful lives extended under New CGAAP
Net (Income)/Expense before Tax	**$ (579,575)**	**$ (539,507)**	

Impact on Revenue Requirement

The impact of the changes to depreciation rates and capitalization policies is a decrease to revenue requirement of $489,282 in the 2014 Test Year. These decreases are a result of:

- Lower depreciation expense under New CGAAP as a result of extending useful lives partly offset by:
    - Increased OM&A expenses under New CGAAP as a result of expensing burdens previously capitalized under Old CGAAP; and
    - Increased return on equity and interest as a result of a higher rate base under New CGAAP (higher working capital allowance and net fixed asset values).

The impact on rate base and net fixed assets as a result of Oakville Hydro's changes to methodology is discussed in further detail in Exhibit 2, Tab 6. The impact on OM&A expenditures is discussed in further detail in Exhibit 4. Oakville Hydro has filed Appendix 2-YB - Summary of Impacts to Revenue Requirement from Accounting Changes under CGAAP below.

Appendix 2-YB
Summary of Impacts to Revenue Requirement
from Accounting Changes under CGAAP or ASPE

Revenue Requirement Component	2014 CGAAP or ASPE with the changes to the policies	2014 CGAAP without the changes to the policies	Difference	Reasons why the revenue requirement component is different under CGAAP or ASPE with the changes to the policies versus CGAAP without the changes to the policies
Closing NBV 2013	$ 155,061,461	$ 154,833,743	$ 227,718	Decrease in burdens capitalized partly offset by decreased amortization due to overall extension to useful lives
Closing NBV 2014	163,057,746	162,390,335	667,411	Decrease in burdens capitalized partly offset by decreased amortization due to overall extension to useful lives
Average NBV	159,059,604	158,612,039	447,565	
Working Capital	23,275,727	22,882,103	393,625	Increase in OM&A @ 13% as non-directly attributable burdens previously capitalized under old CGAAP are now expensed under new CGAAP
Rate Base	182,335,331	181,494,142	841,189	
Return on Rate Base	10,886,814	10,836,588	50,225	
			0	
OM&A	19,418,184	16,390,301	3,027,884	Overhead costs previously capitalized under Old CGAAP
Depreciation	8,611,141	12,178,533	-3,567,391	Decrease in expense as useful lives under New CGAAP are extended
PILs or Income Taxes	0	0	0	
			0	
Less: Revenue Offsets	-2,035,753	-2,035,753	0	
			0	
			0	
			0	
Insert description of additional item(s)			0	
Total Base Revenue Requirement	$ 36,880,386	$ 37,369,668	($489,282)	

Non-utility Business

Oakville Hydro Electricity Distribution Inc. is not currently engaged in renewable generation activities. These activities are conducted by Oakville Hydro Electricity Distribution Inc.'s affiliate, Oakville Hydro Energy Services Inc. However, Oakville Hydro Electricity Distribution Inc. has installed a small number of photovoltaic devices on distribution pole-tops as a pilot project. The capital costs of $38,000 are included in Oakville Hydro's rate base.

Oakville Hydro Electricity Distribution Inc. is engaged in the delivery of the Ontario Power Authority's conservation and demand management programs. The accounting for these activities is segregated from Oakville Hydro's rate regulated activities in accordance with the Board's Accounting Procedures Handbook For Electricity Distributors.

Status of Board Directives from Previous Board Decisions

2010 Cost of Service Application (EB-2009-0271):

Oakville Hydro filed a Cost of Service Application with the Board on August 28, 2009. On February 18, 2010, Oakville Hydro filed additional evidence. A settlement conference was held on April 6 and 7, 2010 at the Board's offices. All parties participated in the settlement conference and, in the Settlement Agreement, the parties agreed to settle all matters. Oakville Hydro filed the Settlement Agreement on April 26, 2010 and, in its Decision and Order on Oakville Hydro's Cost of Service Application, the Board accepted the settlement agreement. As a result of the Settlement Agreement, there were three directives from the 2010 cost of service application.

(1) In the Settlement Agreement, the parties agreed to a decrease of $680,419 related to the fibre optic network lease Oakville Hydro entered into with its then affiliate, Blink Communications Inc. as its auditors had advised that because the lease represented a

related party transaction, the value of the assets was to be recorded at the Net Book Value of $24,154, rather than the originally proposed value of $704,573[2]. However, the Parties agreed this may not reflect the appropriate approach for rate making purposes and agreed that Oakville Hydro may, in a subsequent cost of service proceeding, provide independent evidence of a more appropriate value. Subsequent to that, Oakville Hydro engaged an independent third party to prepare a valuation of the fibre optic network. Oakville Hydro is filing this third party evaluation as an appendix to Exhibit 2 of this Application and is requesting that the asset be added to the 2014 Test Year rate base at its depreciated value of $693,470.

(2) As part of the settlement agreement, Oakville Hydro agreed to file a formal third party corporate cost allocation study as part of its next Cost of Service Application[3]. Oakville Hydro has complied with this requirement and is filing this formal third party study as an appendix to Exhibit 4 of this Application.

(3) In its 2010 Cost of Service application, Oakville Hydro proposed a phase-in period to adjust its revenue-to-cost ratios, moving the Sentinel Lighting and Street Lighting rate classifications from their 2010 position to the lower boundary of the Board's target ranges during 2011 and 2012. Oakville Hydro has complied with this directive and as of its 2012 IRM application (EB-2011-0189), Sentinel Lighting and Street Lighting Revenue-to-Cost Ratios have been moved to within the Board's target ranges.

2011 Incentive Regulation Mechanism Application (EB-2010-0104)

In its Decision and Order in Oakville Hydro's 2011 Incentive Regulation Mechanism Application (EB-2010-0104), the Board directed Oakville Hydro to report the difference between

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[2] Settlement Agreement, EB-2009-0271, page 8

[3] Settlement Agreement, EB-2009-0271, page 12.

the capital expenditure that it had proposed in its application and the actual spending and to report annually on the actual amount spent. Oakville Hydro has complied with the Board's directives and is requesting approval to include the actual spending in the calculation of rate base in this Application.

Directives from Stand Alone Smart Meter Application (EB-2012-0193)

In its Decision and Order in Oakville Hydro's Stand-alone Smart Meter Application (EB-2012-0193), the Board directed Oakville Hydro to record capital and operating costs for new smart meters and the operations of smart meters in regular capital and operating expense accounts. The Board also authorized Oakville Hydro to continue to use the established Stranded Meter sub-account to record and track costs associated with stranded conventional meters and to bring forward those costs for disposition in Oakville Hydro's next Cost of Service Application. Oakville has complied with the Board's directives and is seeking approval for the disposition of the stranded meter sub-account in Exhibit 9 of this Application

Conditions of Service

Oakville Hydro's current Conditions of Service can be found on its website at www.oakvillehydro.com/pdf/conditionsofservice.pdf. Oakville Hydro's Conditions of Service include charges for work done in response to customer requests for services that are not part of the standard services, damages to Oakville Hydro's equipment and theft of power on a cost recovery basis. Oakville Hydro believes that this practice is consistent with the Board's principal of cost causality.

If the Board approves Oakville Hydro's request for a new Embedded Distributor rate class, Oakville Hydro will update its Conditions of Service accordingly.

Response to Letters of Comment

Oakville Hydro will respond to any matters that are raised in letter of comment filed with the Board during the course of this proceeding and file those responses as additional evidence.

Revenue Requirement Work Form

Oakville Hydro's completed Revenue Requirement Work Form is provided in the following pages.

Appendix A

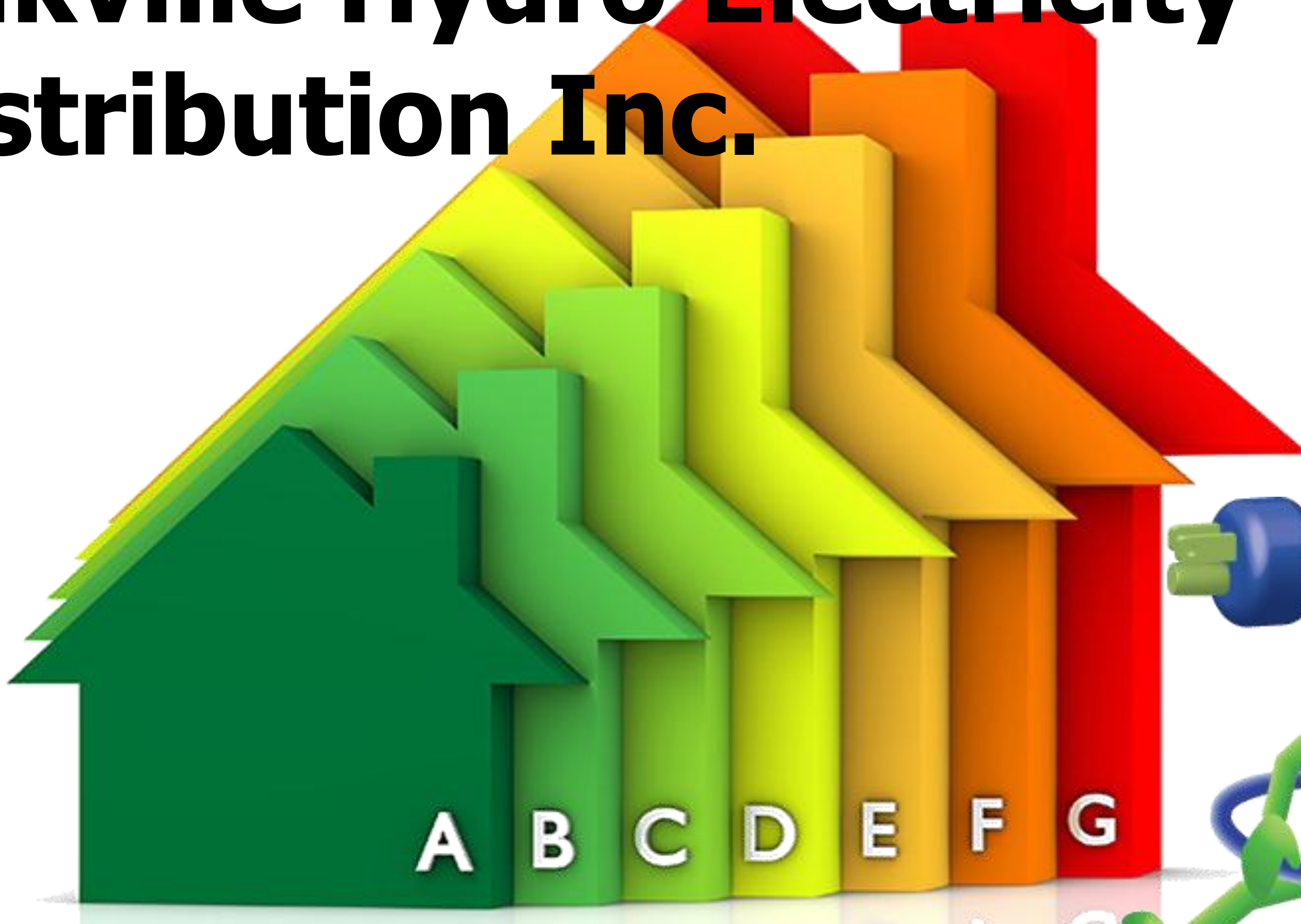
Customer Satisfaction Survey

Executive Summary

This report has been identified as being Confidential or Proprietary by the author(s). However, Oakville Hydro has received the express permission of the author(s) to submit the report to the Ontario Energy Board in support of its 2014 Cost of Service Application (EB-2013-0159). The author(s) have been advised that the report, in its entirety, will form part of the public record in this proceeding.

Oakville Hydro Electricity Distribution Inc.

OAKVILLE HYDRO



UtilityPULSE

15th Annual Electric Utility Customer Satisfaction Survey

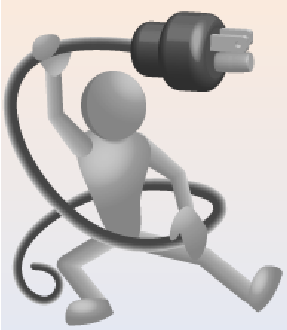
The purpose of this report is to profile the connection between Oakville Hydro and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information that will support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

This is privileged and confidential material and no part may be used outside of Oakville Hydro Electricity Distribution Inc. without written permission from UtilityPULSE, the electric utility survey division of Simul Corporation.

All comments and questions should be addressed to:



Sid Ridgley, UtilityPULSE division, Simul Corporation

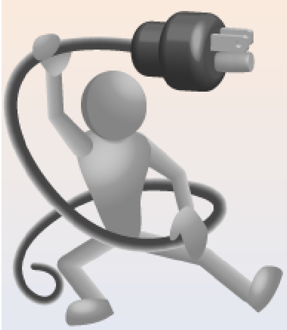
Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Executive summary

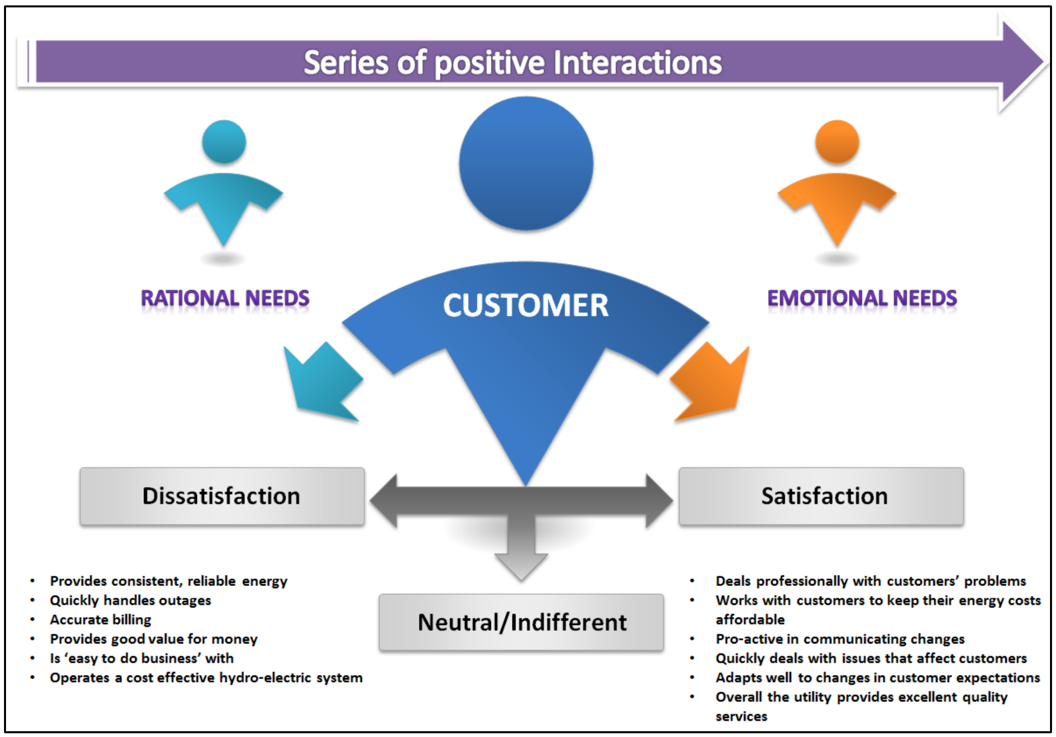
“Putting the Consumer First” was part of the title of the *Report of the Ontario Distribution Sector Review Panel.* Its findings and recommendations add an additional level of challenges and opportunities. While the Report challenges the structural nature and efficiency of LDCs in Ontario, the “customer” remains focused on their own needs and expectations. The customer is primarily concerned about their overall costs for their electricity rather than the costs of the individual components of producing, transmitting, distributing and regulating electricity.

For the past 15 years, the only constant Ontario LDCs and their customers have faced is constant change. With topics such as SMART Meters, SMART Grid, green energy, infrastructure renewal, coupled with the recommendations from the Ontario Distribution Sector Review Panel, it is easy to predict that change will continue – for many years to come. One of the challenges for utilities today is to determine how to educate, empower and engage their residential and small business customers. The goal for utilities is to cut through the fog of fear, misinformation and confusion that exists amongst its customers, regarding a myriad of subjects, while retaining a very high level of trust, respect and credibility.

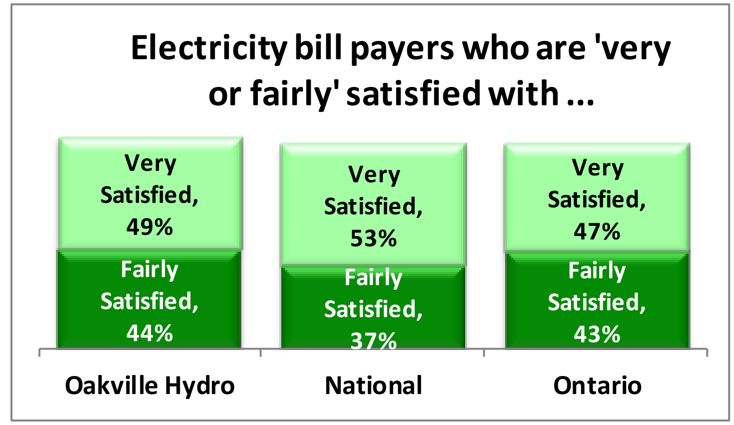


Trust and credibility are the foundational building blocks for ensuring that customers have both their rational and emotional requirements fulfilled. The attributes which help an LDC to be seen as trusted and highly credible are: knowledge, integrity, involvement and trust. On demonstrating Credibility and Trust, Oakville Hydro has done well. Overall, Oakville Hydro 85% [Ontario 82%; National 82%].

Customers, as human beings, are both rational and emotional. The rational side of the customer holds the LDC accountable for doing its job (as contracted), thereby fulfilling the customer's basic needs. The emotional side of the customer is about fulfilling expectations. Meeting rational needs – at best – gets the customer to a neutral state and at worst creates dissatisfaction. Emotional needs, when met, assuming base level rational needs are met, can move a customer from neutral to higher levels of satisfaction.

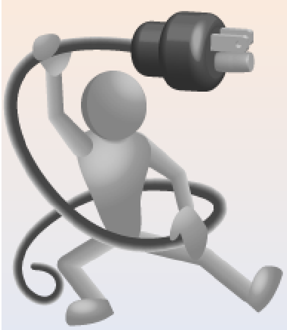


The old adage, “You cannot command respect, you have to earn respect” is a lesson that aptly describes the loyalty effect with customers. Many people mistakenly think doing a good job will lead to loyalty; that a satisfied customer equals a loyal customer. Customers have expectations of their electric utility that go far beyond “keeping the lights on”, “billing me properly”, and “restoring power quickly”.



- **Satisfaction** happens when utility core services meet or exceed customer’s needs, wants, or expectations.
- **Loyalty** occurs when a customer makes an emotional connection with their electric utility on a diverse range of expectations beyond core services.

Satisfaction alone does not make a customer loyal; a willingness to commit and advocate for a company along with satisfaction identifies the three basic customer attitudes which underpin loyalty profiles. While satisfaction is an important component of loyalty, the loyalty definition needs to incorporate more attitudinal and emotive components.

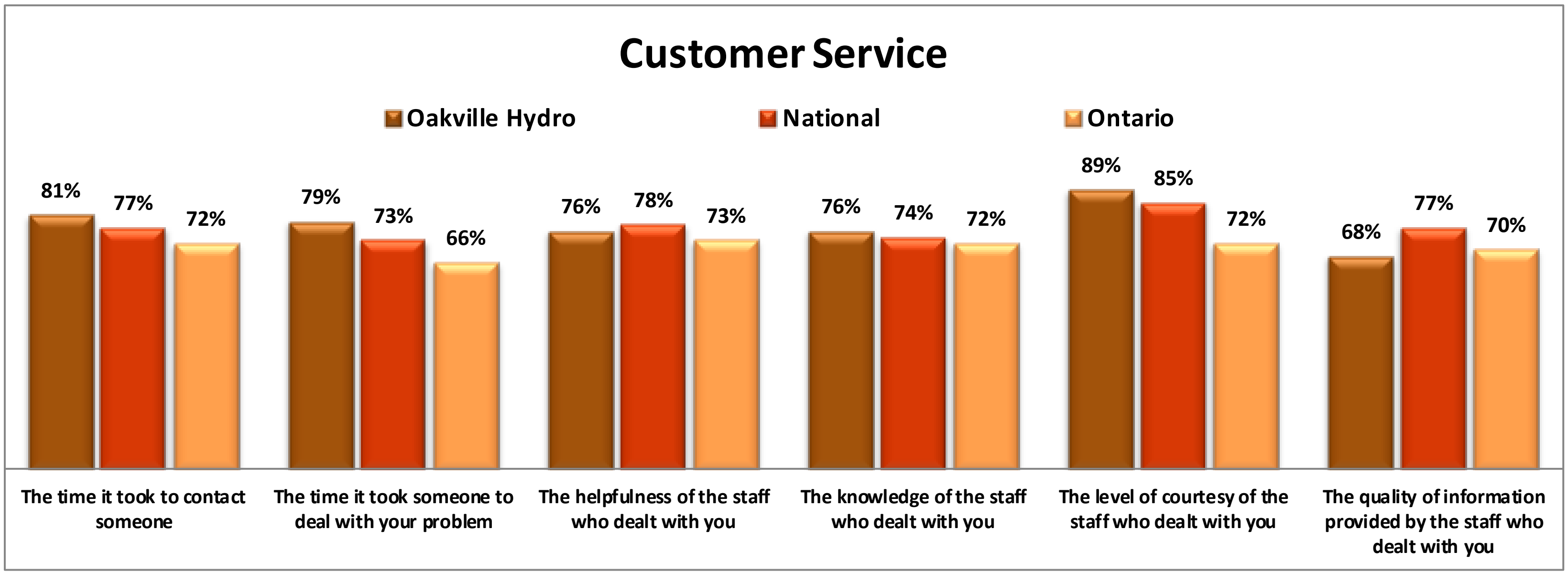


Oakville Hydro SATISFACTION SCORES – Electricity customers’ satisfaction

Top 2 Boxes: ‘very + fairly satisfied’	2013	2012	2011	2010
PRE: Initial Satisfaction Scores	93%	89%	88%	-
POST: End of Interview	93%	92%	92%	-

Base: total respondents / (-) not a participant of the survey year

Customers have needs and expectations AND they will have problems. How those problems are dealt with are “proof points” which will validate or invalidate their perceptions. Customer problems are far more diverse than they have ever been, thereby, causing customer service to change in response to those problems and needs. Given the increase in fragmentation of customer type and customer problems, the need for building a customer-centric culture in line with customers’ needs, preferences and expectations is important when customer satisfaction is important to the organization.



Base: total respondents who contacted the utility

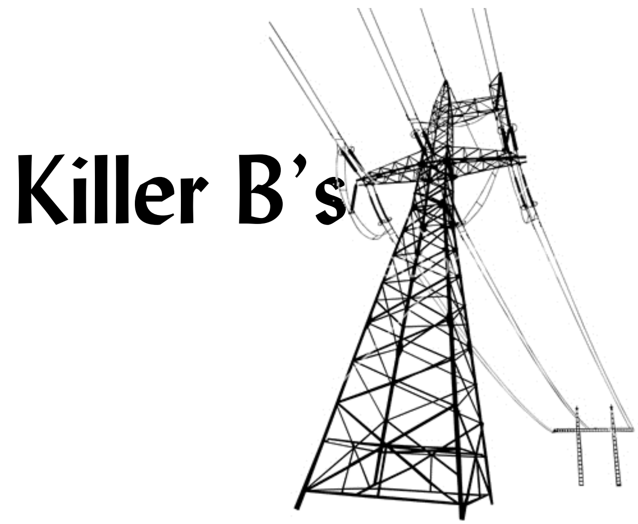
The Killer B's (Blackouts and Bills)

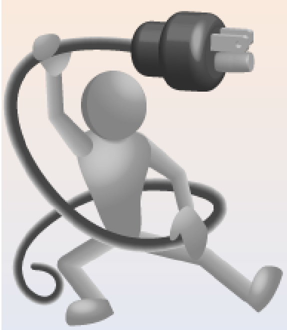
It is inevitable that there will be blackouts/power outages – the key is how a utility anticipates outages and deals with them. It should also be noted that there is a disconnect between what a utility might call a "billing problem" and what a customer defines as a "billing problem". Though both viewpoints are valid, employees need to be trained to answer those that cause the most concern with customers.

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months

	Oakville Hydro	National	Ontario
2013	37%	41%	35%
2012	39%	44%	46%
2011	30%	43%	43%
2010	-	45%	41%

Base: total respondents / (-) not a participant of the survey year





Percentage of Respondents indicating that they had a Billing problem in the last 12 months

	Oakville Hydro	National	Ontario
2013	9%	8%	10%
2012	7%	12%	13%
2011	9%	10%	16%
2010	-	10%	12%

Base: total respondents/ (-) not a participant of the survey year

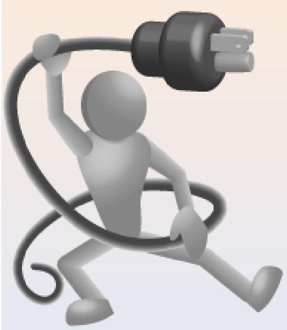
What do customers think about electricity costs?

There is a correlation between ability to pay and satisfaction with higher earners reporting the highest levels of initial satisfaction with their utility. It is also true that emotional connectivity, i.e. loyalty, also plays a role about what customers think about costs. Out of all the Ontario survey respondents this year, only 17% of Secure customers vs 43% of At Risk customers report that they sometimes or often worry about paying their electricity bill.

Is paying for electricity a worry or major problem …

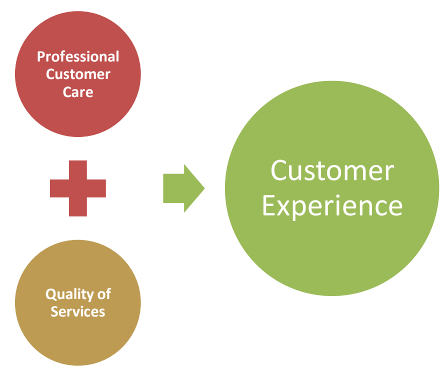
	Oakville Hydro	National	Ontario
Not really a worry	77%	70%	66%
Sometimes I worry	15%	18%	21%
Often it is a major problem	5%	8%	11%
Depends	1%	2%	1%

Base: total respondents



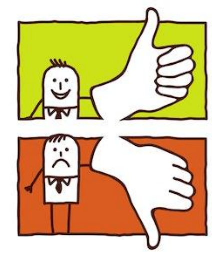
Customer Experience Performance rating (CEPr)

New for 2013 is the Customer Experience Performance rating (CEPr). Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization.



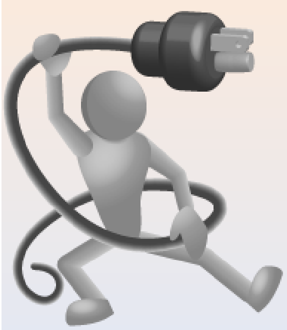
Customer Experience Performance rating (CEPr)			
	Oakville Hydro	National	Ontario
CEPr: all respondents	85%	83%	83%
CEPr: respondents *who have* contacted their utility	82%	79%	77%
CEPr: respondents *who have not* contacted their utility	86%	84%	85%

Base: total respondents



The key is handling every individual element of an interaction with a customer so that he/she feels good at the end of the whole interaction and the utility achieves its business objectives.

While an excellent transaction today creates a positive experience today, the perception created is that future transactions will be excellent too, which is how you want your customers to feel. Of course, a negative transaction creates the perception that future transactions will be negative.



Customer Engagement Index (CEI)

UtilityPULSE has been researching this topic for the past 2 years and we have found that there are 4 basic types of definitions associated with the term called “customer engagement”. Here are the basic types:

1- Participation in programs or service offerings

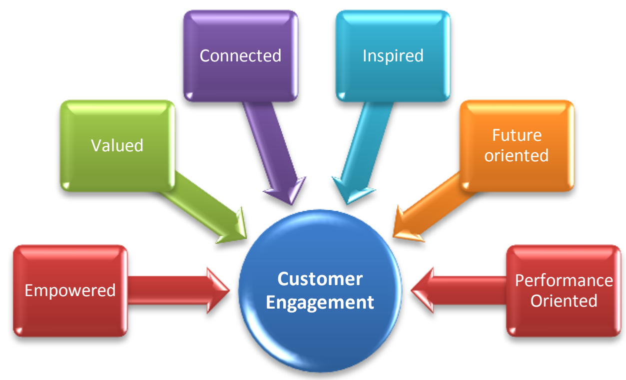
2- Pro-active “reach-out” to customers

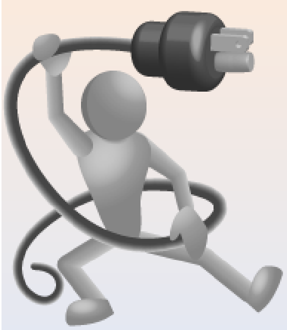
3- Customer loyalty

4- How customers think, feel and act towards the organization that serves them.

Drawing from our 25+ years of experience working with enterprises in both the private and public domains, we believe that basic types 1 & 2 are too simplistic and tend to be an efficiency measurement. Whereas types 3 & 4 are more valuable to the organization especially when a key corporate goal is to create an operationally effective place to do business with – essentially an effectiveness and outcomes oriented measurement.

Engagement is how customers think, feel and act towards the organization. As such, ensuring that customers respond in a positive way requires that they are rationally satisfied with the services provided AND emotionally connected to your LDC and its brand. The more frequently and consistently an organization's products and services can connect with a customer, especially on an emotional level, the stronger and deeper the customer becomes engaged with the organization. The six dimensions of an outcome based definition of customer engagement are: empowered, valued, connected, inspired, future oriented and performance oriented.



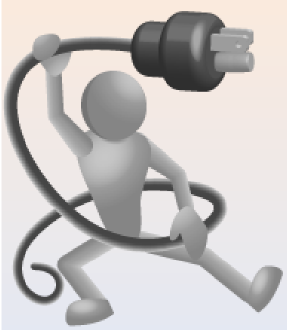


Utility Customer Engagement Index (CEI)			
	Oakville Hydro	**National**	**Ontario**
CEI	84%	81%	81%

Base: total respondents

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide your utility with a snapshot of performance – it represents the sum total of respondents' ratings on 6 categories of attributes that research has shown are important to customers for influencing satisfaction and affinity levels with their utility.



Oakville Hydro UtilityPULSE Report Card®

Performance

	CATEGORY	Oakville Hydro	National	Ontario
1	**Customer Care**	**A**	**B+**	**B+**
	Price and Value	B+	B	B
	Customer Service	A	B+	A
2	**Company Image**	**A**	**A**	**A**
	Company Leadership	A	A	A
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A	A	A
	OVERALL	**A**	**A**	**A**

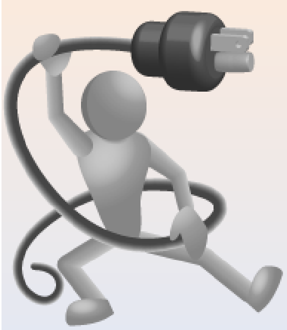
Base: total respondents

Corporate Image

Organizations today, are always under scrutiny and have to consider the reality AND perception of their image. Increasingly, organizations have realized that the management of a strong positive image with various stakeholders can be beneficial.

Attributes strongly linked to a hydro utility's image			
	Oakville Hydro	National	Ontario
Is a respected company in the community	88%	83%	84%
Maintains high standards of business ethics	86%	81%	81%
A leader in promoting energy conservation	81%	80%	80%
Keeps its promises to customers and the community	84%	81%	82%
Beyond providing jobs and paying taxes, is socially responsible	84%	79%	79%
Is a trusted and trustworthy company	85%	83%	83%
Adapts well to changes in customer expectations	73%	74%	73%
Is 'easy to do business with'	85%	82%	81%
Overall the utility provides excellent quality services	85%	85%	83%
Operates a cost effective hydro-electric system	74%	72%	68%

Base: total respondents with an opinion



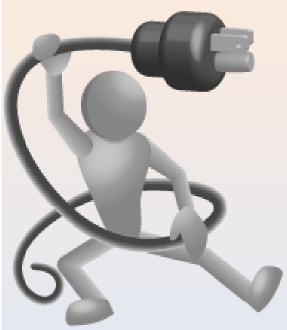
Supplemental Insights

Recognizing that customers' interests and needs continue to shift, we have provided data and SMART insights, on a number of subjects such as e-care, e-billing, conservation and more.

SMART Meters & SMART Grid

Do economic incentives have an impact on resource consumption patterns? *73% of Oakville Hydro respondents agree strongly or somewhat that Time-of-Use billing has changed the way in which they consume electricity on a day-to-day basis.*

SMART metering is also a key element of SMART grid technology. This year's survey probed around the concept of SMART grid, its importance and support towards working with neighbouring utilities. It is clear that the need for education is immense. It is also clear that the majority of respondents are very + somewhat supportive of the utility working with neighbouring utilities on SMART grid initiatives.



Level of knowledge about the SMART Grid

	Ontario LDCs	Oakville Hydro
I have a fairly good understanding of what it is and how it might benefit homes and businesses	7%	8%
I have a basic understanding of what it is and how it might work	17%	18%
I've heard of the term, but don't know much about it	33%	34%
I have not heard of the term	42%	39%
Don't know	1%	1%

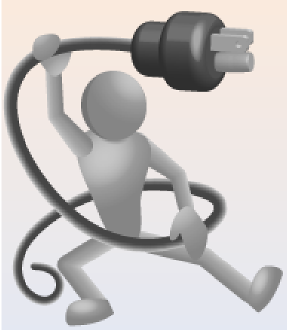
Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

Importance of pursuing implementation of the SMART Grid		
	Ontario LDCs	**Oakville Hydro**
Very important	23%	24%
Somewhat important	30%	28%
Neither important or unimportant	9%	13%
Somewhat unimportant	5%	7%
Unimportant	10%	8%
Don’t know	23%	20%

Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility

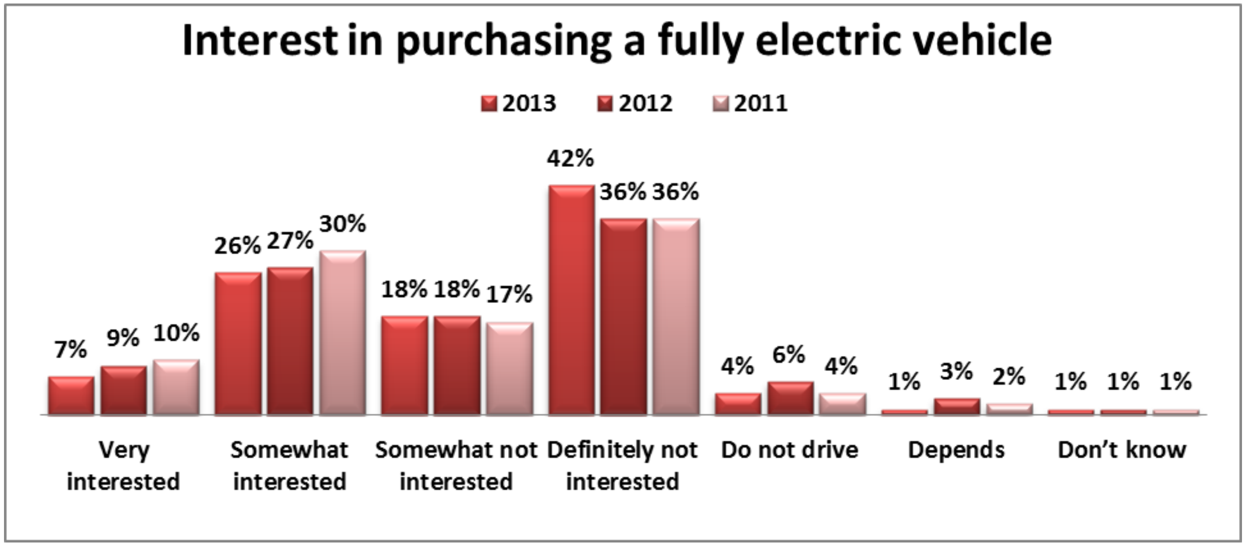
Support towards working with neighbouring utilities on SMART Grid initiatives		
	Ontario LDCs	**Oakville Hydro**
Very supportive	38%	42%
Somewhat supportive	37%	37%
Neither supportive or unsupportive	4%	5%
Somewhat unsupportive	2%	2%
Unsupportive	6%	8%
Don’t know	12%	6%

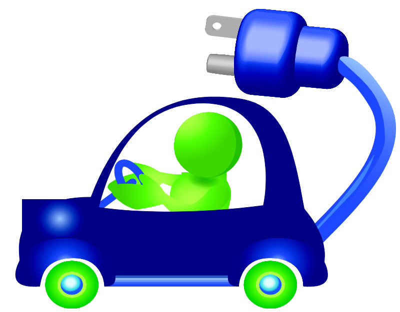
Base: An aggregate of respondents from 2013 participating LDCs / 90% of total respondents from the local utility



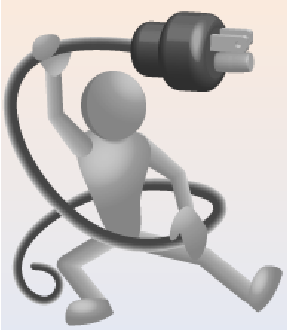
Purchasing an Electric Vehicle

Looking at age demographics, 22% of older respondents (55+) versus 47% of respondents aged 35-54 and 43% aged 18-34 are in favor of EVs replacing conventional cars.





Base: total respondents in the Ontario Benchmark survey



Energy Conservation & Efficiency

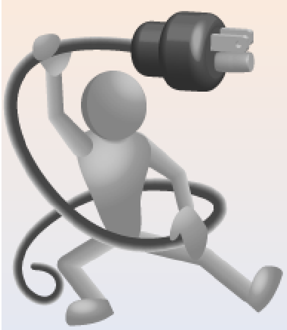
Improving energy efficiency does not mean that customers have to give up or forgo activities to save energy. Rather, new technologies and more effective behaviour will actually allow customers to do more, improving their living conditions rather than reducing their comfort. Energy efficiency can be broken down into two areas: *better use of energy through improved energy-efficient technologies;* and

energy saving through changes in customer awareness and behaviour. During the survey interview process, we asked *"what are the 1 or 2 barriers for creating higher levels of energy efficiency?"* 21% identified "costs involved in making equipment/appliance changes", and 12% identified "lack of knowledge or lack of information". Respondents were asked: *"What will you be doing to conserve energy?"*

Efforts to conserve energy

Oakville Hydro	Yes	No	Already Done	Don't Know
Install energy-efficient light bulbs or lighting equipment	20%	11%	68%	1%
Install timers on lights or equipment	16%	43%	38%	2%
Shift use of electricity to lower cost periods	21%	19%	58%	2%
Install window blinds or awnings	11%	25%	62%	2%
Install a programmable thermostat	14%	12%	73%	1%
Have an energy expert conduct an energy audit	8%	67%	22%	3%
Removing old refrigerator or freezer for free	12%	44%	40%	4%
Join the peaksaverPLUS™ program	19%	50%	19%	12%
Replacing furnace with a high efficiency model	10%	38%	50%	1%
Replacing air-conditioner with a high efficiency model	13%	38%	48%	2%
Use a coupon to purchase qualified energy saving products	31%	43%	22%	4%

Base: 90% of total respondents from the local utility



E-care and E-billing

For any service provider including electric utilities, using the Internet for online customer care and electronic billing involves a number of interrelated requirements, including a customer's ability to: sign up for and change their services using the internet, find answers to their questions online about their accounts, learn about products, services and topics, i.e., green energy, electricity pricing, etc. It is about giving control to the customer.

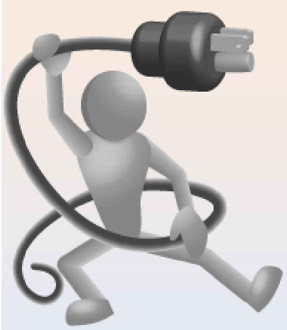
86% of Ontario respondents have access to the internet and 27% have accessed their utility's website in the last six months.

Consumers will eventually adopt electronic billing and online customer care as many industries/companies begin providing consumer bills online, and critical mass is reached.

Using the internet for billing

	Ontario LDCs
I am already receiving my hydro bill electronically	10%
I use on-line banking and will definitely be requesting that my bill be sent electronically	11%
I use on-line banking but prefer to have paper statements	30%
I prefer to have the paper copy of my bills	23%
I don't use on-line banking	17%

Base: An aggregate of respondents from 2013 participating LDCs

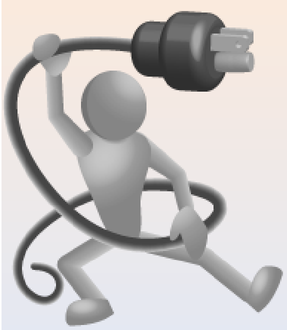


Monthly Billing

Effective billing and collection systems are a critical component for ensuring the viability of a service provider. Improving these has an immediate impact on cash flow management and work flow efficiency for the service provider. Shorter billing cycles, i.e. monthly, give customers a more current view of their consumption patterns and given the shorter consumption cycle, a potentially lower bill which would be easier on household budgets.

Oakville Hydro undertook probing their customers for their feelings regarding the possibility of a monthly billing cycle and its ramifications.

- 58% agree that monthly billing would be preferred by most customers.
- 63% agree that hydro bills, like gas and telephone bills, should be billed monthly.
- 72% agree that monthly billing would assist in managing expenses.
- 57% agree that they would be willing to go with paperless billing if billed monthly.
- 52% would not be willing to go on a pre-authorized payment plan if billed monthly.
- 75% would not agree to pay $1 or $2 more per bill to acquire monthly billing.



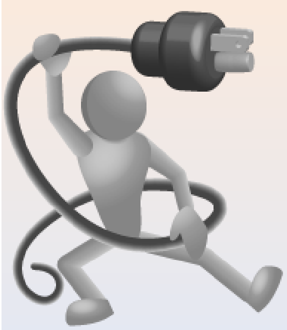
Social Media

Social media is evolving at an incredible pace. Importantly, it seems to represent a shift in how people discover, read and share news, information and content. Respondents of this year's survey were asked *"how likely they would use social media such as twitter®, facebook® (and others) as a resource for energy efficiency tips or to help manage your electricity use"…*

Likelihood of using Social Media

	Ontario LDCs	Ontario LDCs Age Group:18-34	Ontario LDCs Age Group: 55+
Very likely	6%	10%	3%
Somewhat likely	11%	17%	6%
Not likely	20%	24%	17%
Not likely at all	61%	48%	68%
Don't have social media account	2%	0%	4%
Don't know	1%	0%	1%

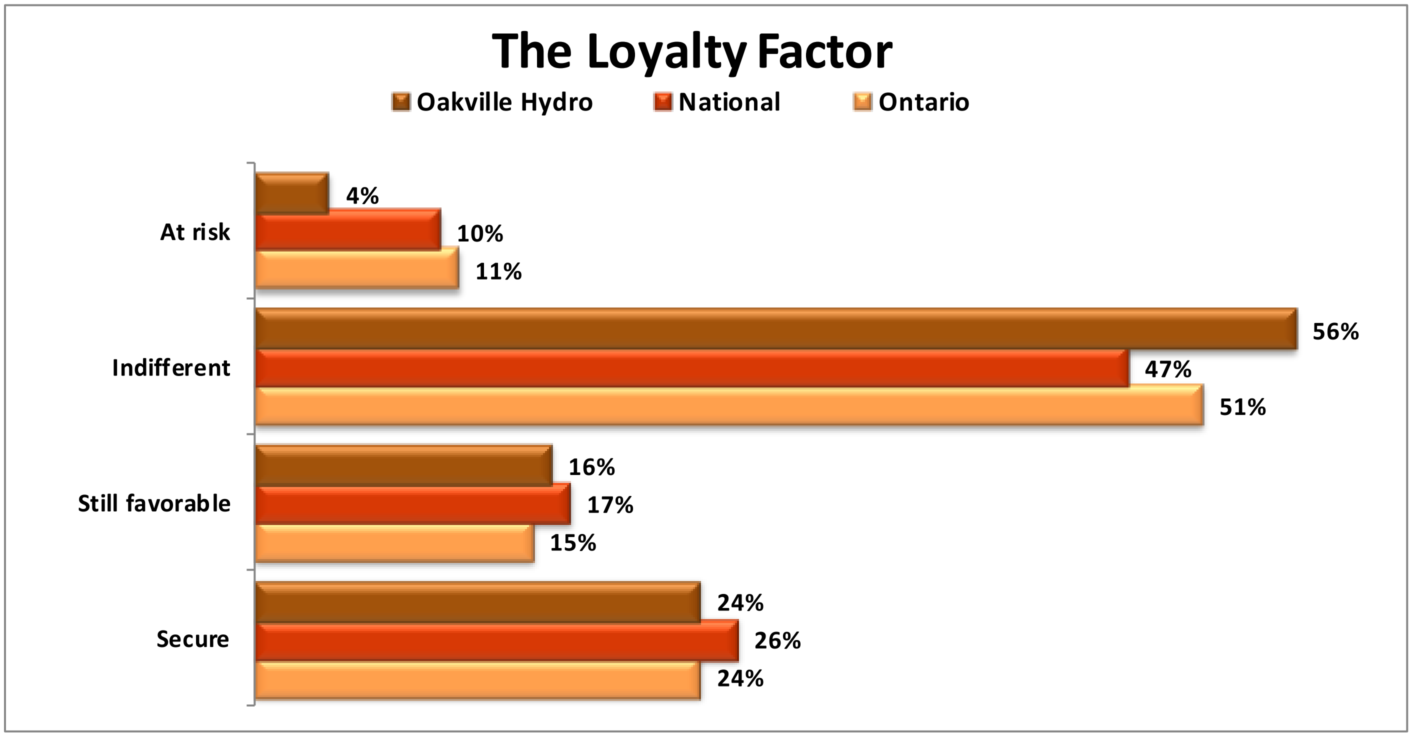
Base: An aggregate of respondents from 2013 participating LDCs



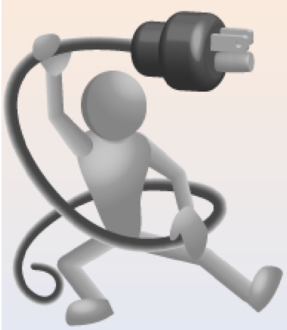
Customer Affinity

Private industry often equates customer loyalty with basic customer retention. If a customer continues to do business with a company, that customer is, by definition, considered to be loyal. If this definition were applied to many companies in the utility industry, all customers would automatically be considered loyal. As such, measuring customer loyalty would appear to be unnecessary.

Natural monopolies (like LDCs) are not really different in what they should measure except that trying to determine which customers are "loyal" or "at risk" is not about a customer's future behaviour but more about their "attitudinal" loyalty (are they advocates?).



Base: total respondents



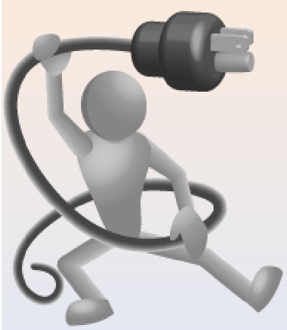
Customer Loyalty Groups				
	Secure	Favorable	Indifferent	At Risk
Oakville Hydro				
2013	24%	16%	56%	4%
2012	22%	14%	57%	7%
2011	21%	12%	58%	9%
2010	-	-	-	-

Base: total respondents / (-) not a participant of the survey year

Electricity customers' loyalty – Is a company that you would like to continue to do business with

Oakville Hydro	2013	2012	2011	2010
Top 2 boxes: 'Definitely + Probably' would continue	80%	80%	75%	-

Base: total respondents / (-) not a participant of the survey year

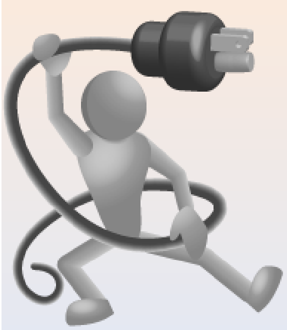


Electricity customers' loyalty – is a company that you would recommend to a friend or colleague

Oakville Hydro	2013	2012	2011	2010
Top 2 boxes: 'Definitely + Probably' would recommend	76%	74%	70%	-

Base: total respondents / (-) not a participant of the survey year

Every LDC has a brand and a brand image, while that image can be affected by events in the industry beyond the control of the LDC, the reality is there is a cost benefit to improving the customer experience, generating higher levels of customer engagement and growing the numbers of Favourable and Secure customers. Providing consistent reliable energy while being seen as 'easy to do business with', along with providing information and support for customers to use electricity more efficiently are core components of a successful relationship with customers.



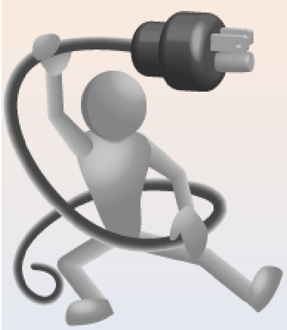
Marketing – Communications

	Oakville Hydro	National	Ontario
Topics that require more pro-active communication			
Cost of electricity is reasonable when compared to other utilities	61%	66%	61%
Works with customers to keep their energy costs affordable	69%	66%	65%
Adapts well to changes in customer expectations	73%	74%	73%
Operates a cost effective hydro-electric system	74%	72%	68%
Provides good value for money	71%	71%	68%
Topics that your utility scores very well on			
Is a trusted and trustworthy company	85%	83%	83%
Respected company in the community	88%	83%	84%
Accurate billing	87%	85%	86%
Overall the utility provides excellent quality services	85%	85%	83%
Provides consistent, reliable energy	90%	90%	90%

Base: total respondents with an opinion

UtilityPULSE is the only enterprise with multiple year customer trend data that appears on the List of Presenters and Submitters in the *Report of the Ontario Distribution Sector Review Panel.* With 14 years of data (15 now that the 2013 survey has been completed), we know that LDCs in Ontario have made excellent progress in the way(s) in which customers are cared for and served – despite the massive amounts of change that have taken place during that same timeframe.

We've often been asked: "What does it take to be seen as having great customer service?" Our answer continues to be "have genuine empathy for customers". If you and your fellow employees don't have it, then your organization will not achieve the highest levels of customer engagement and affinity as may be possible. This requires Oakville Hydro to ensure that it is truly embracing the strategic intent of being "customer centric" AND it requires the establishment of a corporate culture that supports both customer and employee engagement.



We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2013 customer satisfaction survey derived from speaking with 402 Oakville Hydro customers [March 21 - April 2, 2013]. After-all, people can't care about the things that they don't know about.

Sid Ridgley
Simul/UtilityPULSE
Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com
June, 2013

Good things happen when work places work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders that lead and a front-line that is inspired. We provide: training, consulting, surveys, diagnostic tools and keynotes. The electric utility industry is a market segment that we specialize in. We've done work for the Ontario Electrical League, the Ontario Energy Network, and both large and small utilities. For fifteen years we have been talking to 1000's of utility customers in Ontario and across Canada and we have expertise that is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	Focus Groups, Surveys, Polls, Diagnostics	Customer Service Excellence
Leadership development	Diagnostics ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP, MBA

Phone: (905) 895-7900 Fax: (905) 895-7970 E-mail: sidridgley@utilitypulse.com or sridgley@simulcorp.com

Appendix B

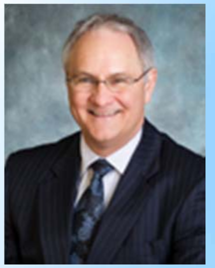
Presentation to Intervenors

OAKVILLE HYDRO
ELECTRICITY
DISTRIBUTION

May 1, 2014 - Cost of Service

August 21, 2013

OAKVILLE HYDRO LEADERSHIP TEAM



Rob Lister, P.Eng., MBA – President and CEO

- 30 years of industry experience
- Board of Directors – Ontario Energy Association
- United Way of Oakville – Campaign Cabinet

Mike Brown, P. Eng., Vice-President, Engineering & Operations and Chief Operating Officer

- 5 years at Oakville Hydro – extensive telecom experience
- EDA operations Advisory Council,
- CEA Distribution Council

Jim Collins, B.Comm., CPA, CA., VP, Corporate and Regulatory Affairs and CFO

- Experience in public reporting in entrepreneurial companies - both public and private
- Board of Director – Halton Learning Foundation
- Audit Committee – Oakville Community Foundation

Mary Caputi, B. Math, CPA, CA., Director, Regulatory Affairs

- 10 years at Oakville Hydro in Finance and Regulatory departments
- Audit Committee – Halton District School Board

OAKVILLE HYDRO

OAKVILLE HYDRO - OVERVIEW

- **2012 Thirteenth largest LDC in Ontario**

  - Distribution Customers served (July 2013)

- Residential	58,673
- Business	6,446
	65,119

  - No significant change in C&I customers

Square kilometres served	143
Electricity peak load 2013	382 MW
Electricity Consumption 2012	1,591 GWh

- New customers in 2011 **913** **(1.4% growth)**
  New customers in 2012 **495** **(0.8% growth)**

OAKVILLE HYDRO

OAKVILLE HYDRO APPLICATION

Board Governance:

- **Experienced – engaged Board of Directors**
  - **Active Board Committees**

Vision – *We energize you!*
Mission – *We provide your best energy and conservation solutions*

- **Corporate Scorecard tied into the Corporate Strategic Plan**

Vision, Mission, Values and Strategic Imperatives

Vision

WE ENERGIZE You

Mission

We provide your best energy and conservation solutions

Sustainability

Values

Safety · *Customer focus* · *Accountability* · *Innovation* · *Teamwork* · *Communications* · *Integrity/ Respect*

Strategic Imperatives

PROFIT
Enhance Shareholder value

SERVICE
Best in the eyes of our customers, employees and stakeholders

PEOPLE
Develop a distinct continuous business improvement-based culture

COMMUNITY
Enhance the brand of Oakville Hydro to facilitate and achieve energy savings in the Oakville community

OAKVILLE HYDRO

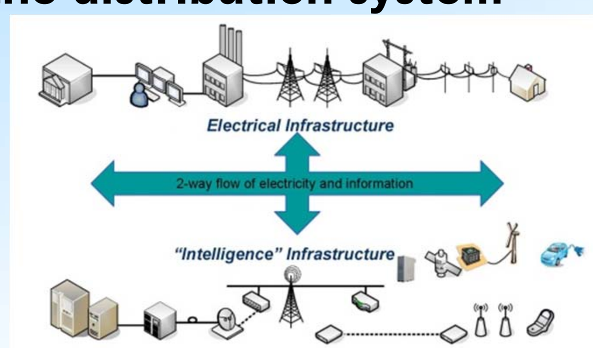
OAKVILLE HYDRO HIGHLIGHTS

Ontario Energy Board
Commission de l'énergie de l'Ontario

- **Regulatory History:**
  - **2010 – Settlement agreement**
  - **2011, 2012 & 2013 Incentive Regulation Mechanism**
  - **2011 Incremental Capital Mechanism – Glenorchy MTS**
  - **2013 Stand Alone Smart Meter Application**

OAKVILLE HYDRO CAPITAL PLAN

- Robust existing distribution system
- Focus on steady, careful and measured investment
  - Glenorchy Emergency Transformer
- Key Elements
  - Cost
  - Reliability
  - Safety
- Incorporating intelligence into the distribution system



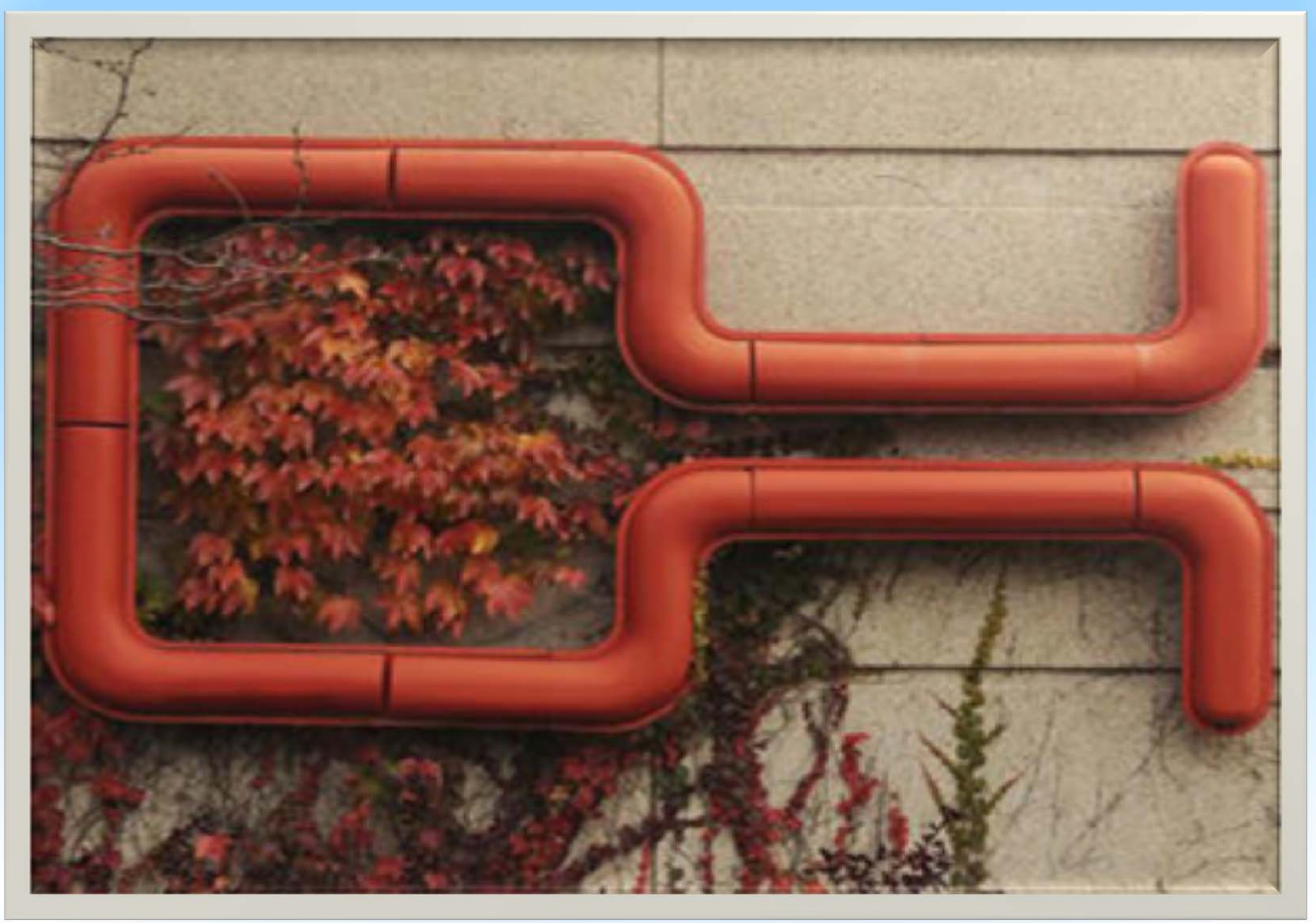
OAKVILLE HYDRO

OAKVILLE HYDRO OM&A

- OM&A has increased
  - Smart Meters
  - Glenorchy Transformer station
  - Labour costs & inflation
- Focus is on Customers
  - B's – Blackouts and Bills
- Change in accounting policies
  - Depreciation rates
  - Burden allocations
- Financial Sustainability

OAKVILLE HYDRO

QUESTIONS



OAKVILLE HYDRO

Appendix C

Financial Statements

Financial Statements of

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

December 31, 2011

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Oakville Hydro Electricity Distribution Inc.

We have audited the accompanying financial statements of Oakville Hydro Electricity Distribution Inc. ("the Entity"), which comprise the balance sheet as at December 31, 2011, and the statements of operations and deficit and cash flows for the year then ended, and notes, comprising 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 an 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 our 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, we 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 Oakville Hydro Electricity Distribution Inc. as at December 31, 2011, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants, Licensed Public Accountants

Hamilton, Canada
March, 29, 2012

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Table of Contents
December 31, 2011

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Balance Sheet
December 31, 2011
(in thousands of dollars)

	2011	2010
ASSETS		
CURRENT		
Cash and cash equivalents	$ -	$ 1,618
Accounts receivable	37,033	31,103
Inventories (Note 3)	4,068	3,632
Prepaid expenses	345	519
	41,446	36,872
OTHER		
Due from related parties (Note 14)	9,851	-
Long term receivable	137	163
Future income taxes (Note 5)	20,557	22,445
	30,545	22,608
CAPITAL ASSETS (Note 6)	141,441	125,216
	$ 213,432	$ 184,696
LIABILITIES		
CURRENT		
Bank overdraft	$ 16,430	$ -
Accounts payable and accrued charges	27,188	27,965
Consumer deposits	5,169	5,008
Capital lease obligation (Note 9)	299	274
	49,086	33,247
OTHER		
Due to related parties (Note 14)	-	6,632
Regulatory liabilities (Note 4)	10,071	17,383
Post employment benefits (Note 7)	7,667	7,473
Capital lease obligation (Note 9)	11,986	12,285
Long-term debt (Notes 10 and 14)	67,946	67,946
	97,670	111,719
	146,756	144,966
SHAREHOLDER'S EQUITY		
SHARE CAPITAL		
Authorized and issued - 1,407 common shares (Note 11)	76,108	54,108
Deficit	(9,432)	(14,378)
	66,676	39,730
	$ 213,432	$ 184,696

See accompanying notes to the financial statements

APPROVED BY THE BOARD

.... Director

Gary Burlett .... Director

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Statement of Operations and Deficit
Year ended December 31, 2011
(in thousands of dollars)

	2011	2010
REVENUE		
Energy and distribution revenue	**$ 170,215**	$ 160,191
Cost of power	**(138,130)**	(130,385)
Net distribution revenue	**32,085**	29,806
Other revenues	**3,474**	4,821
	35,559	34,627
EXPENSES		
Personnel costs	**11,442**	10,723
Contract services	**3,211**	2,070
Property and occupancy costs	**1,176**	1,098
Material costs	**289**	383
Other costs	**4,552**	4,477
Costs allocated to capital	**(6,087)**	(5,793)
	14,583	12,958
EARNINGS BEFORE AMORTIZATION, INTEREST AND INCOME TAXES	**20,976**	21,669
AMORTIZATION	**(10,220)**	(9,997)
INTEREST (Notes 10 and 14)	**(5,834)**	(5,344)
INCOME BEFORE INCOME TAXES	**4,922**	6,328
PROVISION FOR INCOME TAXES (Note 5)	**(24)**	1,673
NET INCOME	**4,946**	4,655
DEFICIT, BEGINNING OF YEAR	**(14,378)**	(19,033)
DEFICIT, END OF YEAR	**$ (9,432)**	$ (14,378)

See accompanying notes to the financial statements

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Statement of Cash Flows
Year ended December 31, 2011
(in thousands of dollars)

		2011		2010
NET INFLOW (OUTFLOW) OF CASH RELATED TO THE FOLLOWING ACTIVITIES				
OPERATING				
Net income	$	**4,946**	$	4,655
Items not affecting cash				
Amortization		**10,220**		9,997
Future income taxes		**892**		973
Post employment benefits		**194**		196
		16,252		15,821
Changes in non-cash working capital items				
Accounts receivable		**(5,904)**		(4,260)
Accounts payable and accrued charges		**(777)**		402
Other		**(262)**		1,074
		9,309		13,037
FINANCING				
Consumer deposits		**161**		(1,035)
Contributions in aid of construction		**2,546**		2,684
Capital lease obligation		**(274)**		(343)
		2,433		1,306
INVESTING				
Amount due from related parties		**5,517**		19,104
Additions to capital assets		**(29,861)**		(29,693)
IRU purchase in excess of net book value		**-**		(681)
Regulatory liabilities		**(5,446)**		(9,715)
		(29,790)		(20,985)
DECREASE IN CASH AND CASH EQUIVALENTS		**(18,048)**		(6,642)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR		**1,618**		8,260
CASH AND CASH EQUIVALENTS (BANK OVERDRAFT), END OF YEAR	**$**	**(16,430)**	$	1,618

See accompanying notes to the financial statements

SUPPLEMENTARY INFORMATION				
Interest paid	**$**	**5,809**	$	5,285
Income tax paid	**$**	**1,183**	$	2,177
Acquisition of capital assets through non-cash capital contributions	**$**	**2,167**	$	1,059
Decrease in regulatory liabilities for stranded meters transferred from fixed assets	**$**	**870**	$	2,795
Decrease in regulatory liabilities related to decrease in future tax assets		**996**		(584)

1. NATURE OF OPERATIONS

Oakville Hydro Electricity Distribution Inc. (the "Corporation"), is a wholly-owned subsidiary of Oakville Hydro Corporation and was incorporated January 28, 2000 under the laws of the Province of Ontario.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the Town of Oakville, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB and adjustments to the Corporation's distribution and power rates require OEB approval.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles and policies set forth in the Accounting Procedures Handbook issued by the Ontario Energy Board under the authority of the Ontario Energy Board Act, 1998:

(a) Measurement uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures thereto. Due to inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

Accounts receivable, regulatory assets and liabilities are stated after evaluation of amounts expected to be collected and an appropriate allowance for doubtful accounts. Inventories are recorded net of provisions for obsolescence. Amounts recorded for amortization of capital assets are based on estimates of useful service life. Post employment benefits are based on certain assumptions, including interest (discount) rates, salary escalation, the average retirement age of employees, employee turnover and expected health and dental costs.

(b) Cash and cash equivalents

Cash and cash equivalents include demand deposits held and may also include short-term investments that are readily convertible to cash without significant loss in value. These short-term investments are comprised of bankers' acceptances and bankers' demand notes issued by Canadian banks.

(c) Inventories

Inventories are stated at the lower of cost and net realizable value and consist of maintenance materials and supplies. Cost is determined on a weighted average basis. Major spare parts and standby equipment are presented as capital assets as they are used during more than one period.

(in thousands of dollars)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(d) Capital assets

Capital assets are recorded at cost, and are amortized over their estimated service lives using the straight-line method of amortization. In the year of addition or completion, a half a year of amortization is taken on the asset. Construction in progress assets are not amortized until the project is complete and in service. The Corporation has not capitalized interest to the cost of assets constructed.

The estimated service lives of the various assets used in calculating amortization are as follows:

Asset	Rate
Buildings and leasehold improvements	50 – 60 years
Transmission and distribution system	15 – 50 years
Building under capital lease	20 years
Office equipment	5 – 10 years
Computer equipment and software	3 – 10 years
Plant and equipment	3 – 20 years

Contributions in aid of construction consist of third party contributions toward the cost of constructing distribution assets and may be refunded by the Corporation based on future economic evaluations, in accordance with the OEB Distribution System Code. They are accounted for as reductions to the cost of related capital assets and are amortized at rates corresponding with the useful lives of the related capital assets, until such time as they are repayable to the third party contributor.

(e) Post employment benefits other than pension

The Corporation provides its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans. The cost of these benefits is expensed as earned by employees through employment service. The excess of the net accumulated actuarial gains (losses) over 10% of the accrued benefit obligation is amortized over the average remaining service period of active employees. The expected average remaining service life of the current active group is 13.5 years.

(f) Regulatory environment

The Corporation is regulated by the OEB, under the authority granted by the Ontario Energy Board Act (1998). The OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment (continued)

The distribution rates of the Corporation are based on a revenue requirement that provides a regulated Maximum Allowable Return on Equity on the amount of the deemed equity component of rate base. The Corporation files a rate application with the OEB annually. Rates are typically effective May 1 to April 30 of the following year. Accordingly, for the first four months of 2011, distribution revenue is based on the rates approved for 2010. Once every four years, the Corporation files a cost of service rate application where rates are rebased through a cost of service review. In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. A cost of service application is based upon a forecast of the amount of operating and capital expenses, debt and shareholder's equity required to support the Corporation's business. An IRM application results in a formulaic adjustment to distribution rates to increase distribution rates for the annual change in the Gross Domestic Product Inflationary Price Index for Final Domestic Demand net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

In August 2009, OHEDI filed a cost of service rate application to adjust its distribution charges effective May 1, 2010. The service rate application was revised on February 18, 2010 and approved on April 30, 2010. The application allows a rate of return of debt and equity of up to 5.62% and 9.85% respectively, based on OHEDI's deemed debt (60%) and equity (40%) capital structure. The application also resulted in the disposition of the cumulative regulatory liabilities balances as at December 31, 2008 in the amount of $7,387 over a three year period.

In September 2010, OHEDI filed an IRM application to adjust its distribution charges effective May 1, 2011. This application requested an increase in rates of 0.18%, and included the disposition and repayment of regulatory liabilities at December 31, 2009 of $3,807 over a one year period. The OEB approved a rate rider to recover capital costs relating to the municipal transformer station in the amount of $19,467 until April 30, 2014.

In September 2011, OHEDI filed an IRM to adjust its distribution charges effective May 1, 2012. This pending application requested an increase of 0.18%, as well as the disposition of balances for payments in lieu of taxes (Deferred PILS) of $3,436 over a one year period.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment (continued)

Regulatory assets/liabilities – net regulatory assets (liabilities) represent costs incurred in excess of amounts billed to customers (or amounts recovered from customers in excess of costs incurred) at the OEB approved rates. These amounts have been accumulated pursuant to the Electricity Act and are deferred for their future resolution in electricity rates. Management assesses the future uncertainty with respect to the final disposition of those amounts and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

At December 31, 2011, regulatory liabilities incur interest at the rate of 1.47 % (2010 – 1.2%) per annum.

Settlement variances - represent amounts that have accumulated since January 1, 2009 and comprise:

a) variances between amounts charged by the Independent Electricity System Operator (“IESO”) for the operation of the wholesale electricity market and grid, various wholesale market settlement charges and transmission charges, and the amounts billed to customers by the Corporation based on the OEB approved wholesale market service rate; and,

b) variances between the amounts charged by the IESO for energy commodity costs and the amounts billed to customers by the Corporation based on OEB approved rates.

Deferred PIL's (see Note 2(h))– represent variances that result from the difference between OEB approved PILs recoverable in electricity distribution services charges and the actual amount of these charges to customers that relates to the recovery of PILs and the impact of any tax rate changes not reflected in the OEB approved PIL’s rates.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment (continued)

Smart Meter Initiative

The Province of Ontario committed to have "Smart Meter" electricity meters installed in all homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit electrical consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals. *Bill 21, Energy Conservation and Responsibility Act*, provides the legislative framework and regulations to support this initiative.

Included in distribution rates effective May 1, 2010 was a charge for Smart Meters of $1.69 per metered customer per month. This rate rider expires April 30, 2012 and the Corporation is applying for an additional rate rider to begin May 1, 2012. The Corporation anticipates that its distribution rates will be adjusted for the incremental investments related to its deployment plan for Smart Meters.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect the distribution rates that the Corporation may charge and the costs that the Corporation may recover, including the balance of its regulatory assets/liabilities.

In the absence of rate regulation, generally accepted accounting principles would require the Corporation to record the costs and recoveries described above in the operating results of the year in which they are incurred and income before income taxes would be $ 4,600 lower than reported (2010 – $ 5,418) and capital assets $1,715 (2010- $7,093) higher than reported.

Green Energy and Green Economy Act

In early 2009, the government tabled the Green Energy and Green Economy Act. This new legislation makes fundamental changes to the roles and responsibilities of local distribution companies ("LDCs") in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The Green Energy and Green Economy Act provides LDCs with the freedom to own and operate a portfolio of renewable power generation assets and will permit them to provide district heating services in their communities through co-generation. LDCs will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. LDCs will also gain new responsibilities to transform their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

On November 1, 2010, OHEDI filed the Conservation and Demand Management ("CDM") Strategy in accordance with the Conservation and Demand Management Code for Electricity Distributors. This plan provided a description of how OHEDI intends to achieve the OEB directed CDM targets.

2. **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)**

(g) Revenue recognition and cost of power

Energy revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power consumed. Revenues from other activities are recorded when goods are delivered or services are provided.

(h) Payments in lieu of income taxes

Under the Electricity Act, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The Corporation accounts for payments in lieu of corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

Payments in lieu of taxes are henceforth referred to as income taxes.

(i) Impairment of long-lived assets

Generally accepted accounting principles require that an impairment loss be recognized when events or circumstances indicate that the carrying amount of the long-lived asset is not recoverable and exceeds its fair value. Any resulting impairment loss is recorded in the period in which the impairment occurs.

The Corporation has determined that there was no impairment of long-lived assets as at December 31, 2011.

(in thousands of dollars)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(j) Financial assets and liabilities

All financial instruments are classified into one of the following categories – held-for-trading, available for sale, held-to-maturity, other liabilities or loans and receivables. All financial instruments are carried on the balance sheet at fair value, except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The company has classified its financial instruments as follows:

Cash and cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Long term receivable	Loans and receivables
Due from related parties	Loans and receivables
Accounts payable	Other liabilities
Consumer deposits	Other liabilities
Long-term debt	Other liabilities

Financial instruments

The Corporation has adopted CICA Handbook Sections 3862 Financial Instruments Disclosures and 3863 Financial Instruments Presentation. The adoption of these standards requires the disclosure of qualitative and quantitative information about the Corporation's risks associated with recognized and unrecognized financial instruments (see Note 13).

3. INVENTORIES

The amount of inventories consumed by the Corporation and recognized as an expense during 2011was $178 (2010 - $202).

4. REGULATORY LIABILITIES

		2011		2010
Settlement of variances	$	2,632	$	(2,426)
Recovery of previous regulatory assets		(5,876)		(5,947)
Other regulatory assets		766		903
Smart Meter deferral		14,306		12,592
Deferred income taxes		(3,436)		(3,046)
Customer liability of future taxes		(18,463)		(19,459)
Balance, end of year	$	(10,071)	$	(17,383)

(in thousands of dollars)

5. INCOME TAXES

		2011		2010
Accounting income before tax	$	4,922	$	6,328
Increase (decrease) in taxable income resulting from:				
Non-deductible and non-taxable items		35		107
Timing differences		(6,227)		(2,863)
Taxable income		(1,270)		3,572
Tax rate		28.25%		31.00%

The income taxes provision consists of:

		2011		2010
Current		(359)		1,107
Future income tax expense relating to current year change in temporary differences		1,888		390
Regulatory liability relating to future tax expense		(996)		583
Other miscellaneous adjustments		(557)		(407)
Income tax provision	$	(24)	$	1,673

Significant components of the Corporation’s future tax balance as at December 31 are as follows:

		2011		2010
Post retirement benefits other than pensions	$	1,917	$	1,868
Plant and equipment		15,986		16,119
Regulatory costs		2,517		4,345
Tax reserves		137		113
Future income taxes	$	20,557	$	22,445

Future income tax rates are calculated using a 25% rate (2010- 25%).

(in thousands of dollars)

6. CAPITAL ASSETS

	2011 Cost	2011 Accumulated Amortization	2011 Net book value	2010 Net book value
Land	$ 1,648	$ -	$ 1,648	$ 301
Land and building under capital lease	11,689	(6,991)	4,698	5,285
Buildings and leasehold improvements	4,124	(1,096)	3,028	2,251
Plant and equipment	5,300	(3,114)	2,186	2,186
Transmission and distribution system	236,195	(80,644)	155,551	125,693
Office equipment	871	(724)	147	168
Computer equipment and software	10,798	(9,025)	1,773	1,131
Construction in progress	2,695	-	2,695	15,237
	273,320	(101,594)	171,726	152,252
Contributions in aid of construction	(38,965)	8,681	(30,284)	(27,036)
Balance, end of year	$ 234,355	(92,913)	141,441	$ 125,216

(in thousands of dollars)

7. POST EMPLOYMENT BENEFITS

The Corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. The Corporation recognizes these post-retirement costs in the period in which the employees earn the benefits, through their services. The accrued benefit liability and the expense for the year ended December 31, 2011 were based on results and assumptions determined by actuarial valuation as at January 1, 2010.

		2011		2010
Accrued benefit obligations, beginning of year	$	6,646	$	5,403
Estimated benefit expense for year		180		176
Interest expense		365		354
Actuarial loss for year		-		978
Benefits paid during the year		(289)		(265)
Accrued benefit obligation, end of year		6,902		6,646
Unamortized actuarial gain		765		827
Accrued benefit liability, end of year	$	7,667	$	7,473

In 2011, the amortization of the actuarial gain was $62 (2010 - $68).

The significant assumptions used are as follows (weighted average):

	2011	2010
Accrued benefit obligation as at December 31:		
Discount rate	5.50%	5.50%
Rate of compensation increase	3.00%	3.00%
Benefit cost of years ended December 31:		
Discount rate	5.50%	5.50%
Rate of compensation increase	3.00%	3.00%
Assumed health care cost trend rates at December 31:		
Initial health care cost trend rate	9.00%	9.00%
Cost trend rate declines to	4.00%	4.00%
Year that rate reaches the rate it is assumed to remain at	2025	2025

(in thousands of dollars)

8. PENSIONS

The Corporation provides a pension plan for its employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. Contributions by the Corporation were at a rate of 7.4% for employee earnings below the year's maximum pensionable earnings and 10.7% thereafter. In 2011, the Corporation made employer contributions of $888 to OMERS (2010 -$753).

9. CAPITAL LEASE OBLIGATION

The Corporation has a capital lease arrangement with the Town of Oakville for the head office at 861 Redwood Square. The initial term of the original lease expired on December 31, 2009 and a new agreement was renegotiated early in 2010 with an effective date of January 1, 2010. At the beginning of 2010, the Corporation derecognized the original lease and recognized the new lease obligation. The carrying value at January 1, 2010 was $9,321. The Corporation recognized a loss on derecognition of $3,581 which has been recorded in retained earnings in accordance with Canadian accounting standards for related party transactions.

The assets under capital lease are included in Capital Assets (see Note 6). The property under capital lease is amortized on a straight-line basis over the term of the lease agreement of 20 years.

Future minimum payments under the capital lease arrangement are as follows for the year-ends:

2012	$ 1,345
2013	1,345
2014	1,345
2015	1,345
2016	1,345
2017 - 2029	17,485
	24,210
Less amount representing interest, imputed at 8.6%	(11,925)
Less current portion	(299)
Long-term portion of lease obligation	$ 11,986

10. LONG-TERM DEBT

The Corporation issued promissory notes effective February 1, 2000, held by the Town of Oakville, with principal repayment due on February 1, 2020. Future rates to be determined annually throughout the balance of the terms of the notes. At December 31, 2011 interest rates in effect were 5.87% (2010 - 6%)

11. SHARE CAPITAL

On December 19, 2011, the Corporation issued 407 common shares with no par value to Oakville Hydro Corporation for $22,000. This issuance was used to settle an account payable to Oakville Hydro Corporation in the amount of $14,470. The remaining balance of $7,530 is outstanding and included in amounts due from related parties on the balance sheet at December 31, 2011.

12. GENERAL LIABILITY INSURANCE

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the electrical utilities in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2011, no assessments have been made.

13. FINANCIAL INSTRUMENTS

The Corporation's fair value measurements are as follows:

Level 1

The carrying values of cash and cash equivalents, accounts receivable, consumer deposits and accounts payable approximate fair value because of the short maturity of these instruments.

Level 3

It is not practicable to determine the fair value of the long-term borrowings from the Town of Oakville due to the limited amount of comparable market information available.

The Corporation's activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

i) Credit risk

Cash and cash equivalents are held in a Canadian Chartered Bank. Financial assets carry credit risk that a counter-party will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Town of Oakville. No single customer would account for revenue in excess of 10% of total revenue.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations. The amount of the allowance for doubtful accounts at December 31, 2011 is $352 (2010 - $297).

13. FINANCIAL INSTRUMENTS (continued)

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2011, approximately $211 (2010 - $ 259) is considered 60 days past due. The Corporation has approximately 64,316 customers, the majority of which are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2011, the Corporation holds security deposits in the amount of $5,169 (2010 - $5,008).

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Consumer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Consumer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Corporation. Interest expense of $24 was incurred on liabilities not held for trading in 2011 (2010 $15).

ii) Market risk

Market risks primarily refer to the risk of loss that result from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates which is set every 4 years, the last one being 2010.

ii) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity exists to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $ 20,000 line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

(in thousands of dollars)

14. RELATED PARTY TRANSACTIONS

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts and balances with the Town of Oakville for the years ended December 31:

		2011		2010
Transactions:				
Revenue				
Energy sales	$	5,471	$	4,186
Expenses				
Interest on capital leases		1,095		1,002
Cashier services		4		3
Tree trimming services		197		259
Garage services		530		474
Property taxes		337		314
Interest on long –term debt		3,988		4,077
Balances:				
Amounts due to:				
Capital leases		12,285		12,559
Long-term debt		67,946		67,946

Included in accounts receivable reported in the balance sheet is $11 owing from the Town of Oakville (2010 - $183) relating to Energy sales and $491 (2010 - $530) relating to other receivables. Included in accounts payable reported in the balance sheet is $3 owing to the Town of Oakville (2010 - $1).

(in thousands of dollars)

14. RELATED PARTY TRANSACTIONS (continued)

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts and balances with the parent, Oakville Hydro Corporation, and its subsidiaries, for the years ended December 31:

	2011	2010
Transactions:		
Revenue		
Billing administration fee	$ 685	$ 1,067
Management fees	322	351
Other charges	291	457
Expenses		
Meter repair and related services	27	7
Management services provided by the parent co.	10	11
Locating services from affiliate	640	363
Dividends paid	-	-
Balances:		
Amounts due from/due to:		
Receivable from related parties	9,851	-
Payable to related parties	-	6,632

Included in accounts payable reported on the balance sheet is $1,359 owing to related parties (2010 - $879). Included in accounts receivable reported on the balance sheet is $15 owing from related parties (2010 – $22)

15. SHORT-TERM CREDIT FACILITIES

The Corporation participates in the pooling of deposits and banking facilities with its parent company OHC and OHC's wholly owned subsidiaries. Under this arrangement, the Corporation has an uncommitted line of $20 million credit facility available with a Canadian chartered bank. As at December 31, 2011, no amount was drawn on this facility. The Corporation has a letter of credit facility available of $16 million with a Canadian chartered bank, of which $15 million has been assigned to secure its primary source of electricity as required by the Independent Electricity System Operator's Settlement Manual.

16. CAPITAL DISCLOSURE

The main objectives of the Corporation when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, comply with covenants related to its credit facilities, prudently manage its capital structure to recover financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2011, shareholder's equity amounts to $66,676 (2010 – $39,730) and long-term debt amounts to $67,946 (2010 - $67,946).

17. EMERGING ACCOUNTING ISSUES

a) Transition to International Financial Reporting Standards

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that would have Canadian GAAP converge with IFRS, effective January 1, 2011 which will require entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved the incorporation of a one year deferral of IFRS 1 into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2012.

The amendment also requires entities that do not prepare its interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

The Corporation has decided to implement IFRS commencing on January 1, 2012.

b) Accounting for rate regulated activities under IFRS

IFRS does not currently provide guidance on accounting for the effects of rate regulation and the recognition of regulatory assets and liabilities. Currently, rate regulated entities do not recognize regulatory assets and liabilities in their IFRS compliant financial statements. The impact of rate regulated accounting has been disclosed in Note 2(f).

17. EMERGING ACCOUNTING ISSUES (continued)

b) Accounting for rate regulated activities under IFRS (continued)

An amendment to IFRS 1, related to the deemed cost exemption for capital assets, was published in May 2010, in the annual "Improvement to IFRSs" amendment document, and applies to entities with operations subject to rate regulation. This exemption permits, at the date of transition, an entity with operations subject to rate regulation, to use the carrying values of property, plant and equipment and intangible assets as deemed cost, thus avoiding the need to restate historical balances using IFRS principles or to determine fair value. The Corporation has elected to apply this exemption for all items of property, plant and equipment and intangible assets subject to rate regulation upon the adoption of IFRS.

On July 28, 2009, the OEB issued its Report of the Board – Transition to IFRS, which contains recommendations on how regulatory reporting requirements should change in response to IFRS. The OEB has now initiated a second phase in its transition project, which involves amending certain regulatory instruments. The Corporation continues to evaluate the potential impacts of the recommendations contained in the Report of the Board on both the activities of the Corporation and its IFRS transition plan.

18. SUBSEQUENT EVENT

Subsequent to year end, the Corporation signed a $22,000 loan agreement with Infrastructure Ontario for a 20 year term, the proceeds of which will be used to replace operating capital used in the 2010-2011 construction of a transmission station in Oakville. Under the terms of the agreement, the Corporation has until December 2012 to draw on this facility at which point the interest rates and repayment schedule will be determined. This transaction has not been recorded in these financial statements.

Financial Statements of

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

December 31, 2012

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Chartered Accountants
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Oakville Hydro Electricity Distribution Inc.

We have audited the accompanying consolidated financial statements of Oakville Hydro Electricity Distribution Inc. ("the Entity"), which comprise the consolidated balance sheet as at December 31, 2012, the consolidated statements of shareholder's equity, operations and cash flows for the year then ended, and notes, comprising 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 an 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 our 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, we 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 consolidated financial position of Oakville Hydro Electricity Distribution Inc. as at December 31, 2012, and the consolidated results of operations and its consolidated cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Hamilton, Canada

April 4, 2013

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Table of Contents
December 31, 2012

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Balance Sheet
December 31, 2012
(in thousands of dollars)

	2012	2011
ASSETS		
CURRENT		
Cash and cash equivalents	**$ 15,769**	$ -
Accounts receivable	**33,362**	37,170
Inventories (Note 3)	**3,216**	4,068
Prepaid expenses	**470**	345
	52,817	41,583
OTHER		
Due from related parties (Note 14)	**-**	9,851
Future income taxes (Note 5)	**19,891**	20,557
	19,891	30,408
CAPITAL ASSETS (Note 6)	**153,506**	141,441
	$ 226,214	$ 213,432
LIABILITIES		
CURRENT		
Bank overdraft	**$ -**	$ 16,430
Accounts payable and accrued charges	**23,928**	27,188
Consumer deposits	**4,639**	5,169
Current portion-long term debt (Note 10)	**390**	-
Capital lease obligation (Note 9)	**325**	299
	29,282	49,086
OTHER		
Regulatory liabilities (Note 4)	**17,038**	10,071
Post employment benefits (Note 7)	**7,641**	7,667
Capital lease obligation (Note 9)	**11,661**	11,986
Long-term debt (Note 10)	**89,492**	67,946
	125,832	97,670
	155,114	146,756
SHAREHOLDER'S EQUITY		
SHARE CAPITAL		
Authorized and issued - 1,407 common shares (Note 11)	**76,108**	76,108
Deficit	**(5,008)**	(9,432)
	71,100	66,676
	$ 226,214	$ 213,432

See accompanying notes to the financial statements

APPROVED BY THE BOARD

.... Director

.... Director

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Statement of Operations and Deficit
Year ended December 31, 2012
(in thousands of dollars)

	2012	2011
REVENUE		
Energy and distribution revenue	$ 186,483	$ 170,215
Cost of power	(149,134)	(138,130)
Net distribution revenue	37,349	32,085
Other revenues	3,813	3,474
	41,162	35,559
EXPENSES		
Personnel costs	12,138	11,442
Contract services	2,882	3,211
Property and occupancy costs	1,102	1,176
Material costs	314	289
Other costs	6,045	4,552
Costs allocated to capital	(5,375)	(6,087)
	17,106	14,583
EARNINGS BEFORE AMORTIZATION, INTEREST AND INCOME TAXES	24,056	20,976
AMORTIZATION	(13,352)	(10,220)
INTEREST (Notes 10 and 14)	(5,566)	(5,834)
INCOME BEFORE INCOME TAXES	5,138	4,922
PROVISION FOR INCOME TAXES (Note 5)	714	(24)
NET INCOME	4,424	4,946
DEFICIT, BEGINNING OF YEAR	(9,432)	(14,378)
DEFICIT, END OF YEAR	$ (5,008)	$ (9,432)

See accompanying notes to the financial statements

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.
Statement of Cash Flows
Year ended December 31, 2012
(in thousands of dollars)

		2012		2011
NET INFLOW (OUTFLOW) OF CASH RELATED TO THE FOLLOWING ACTIVITIES				
OPERATING				
Net income	$	4,424	$	4,946
Items not affecting cash				
Amortization		13,352		10,220
Future income taxes		1,554		892
Loss on disposal of fixed asset		12		-
Post employment benefits		(26)		194
		19,316		16,252
Changes in non-cash working capital items				
Accounts receivable		3,808		(5,904)
Accounts payable and accrued charges		(3,260)		(777)
Other		601		(262)
		20,465		9,309
FINANCING				
Consumer deposits		(530)		161
Contributions in aid of construction		1,100		2,546
Long term debt		21,936		-
Capital lease obligation		(299)		(274)
		22,207		2,433
INVESTING				
Amount due from related parties		9,851		5,517
Additions to capital assets		(14,064)		(29,861)
Regulatory liabilities		(6,260)		(5,446)
		(10,473)		(29,790)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		32,199		(18,048)
CASH AND CASH EQUIVALENTS (BANK OVERDRAFT), BEGINNING OF YEAR		(16,430)		1,618
CASH AND CASH EQUIVALENTS (BANK OVERDRAFT), END OF YEAR	$	15,769	$	(16,430)

See accompanying notes to the financial statements

SUPPLEMENTARY INFORMATION				
Interest paid	$	5,566	$	5,809
Income tax paid	$	(3,477)	$	1,183
Acquisition of capital assets through non-cash capital contributions	$	1,429	$	1,837
Increase in regulatory liabilities for stranded meters transferred from fixed assets	$	2,342	$	(870)
Increase in regulatory liabilities related to increase in future tax assets	$	889	$	(996)
Increase in fixed assets for smart meters transferred from regulatory liabilities	$	10,123	$	-
Decrease in regulatory liabilities for stranded meters transferred from inventory	$	(126)	$	-

1. NATURE OF OPERATIONS

Oakville Hydro Electricity Distribution Inc. (the "Corporation"), is a wholly-owned subsidiary of Oakville Hydro Corporation and was incorporated January 28, 2000 under the laws of the Province of Ontario.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the Town of Oakville, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB and adjustments to the Corporation's distribution and power rates require OEB approval.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles and policies set forth in the Accounting Procedures Handbook issued by the Ontario Energy Board under the authority of the Ontario Energy Board Act, 1998:

(a) Measurement uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures thereto. Due to inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

Accounts receivable, regulatory assets and liabilities are stated after evaluation of amounts expected to be collected and an appropriate allowance for doubtful accounts. Inventories are recorded net of provisions for obsolescence. Amounts recorded for amortization of capital assets are based on estimates of useful service life. Post employment benefits are based on certain assumptions, including interest (discount) rates, salary escalation, the average retirement age of employees, employee turnover and expected health and dental costs.

(b) Cash and cash equivalents

Cash and cash equivalents include demand deposits held and may also include short-term investments that are readily convertible to cash without significant loss in value with a term of less than 3 months.

(c) Inventories

Inventories are stated at the lower of cost and net realizable value and consist of maintenance materials and supplies. Cost is determined on a weighted average basis. Major spare parts and standby equipment are presented as capital assets as they are used during more than one period.

(in thousands of dollars)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(d) Capital assets

Capital assets are recorded at cost, and are amortized over their estimated service lives using the straight-line method of amortization. In the year of addition or completion, a half a year of amortization is taken on the asset. Construction in progress assets are not amortized until the project is complete and in service. The Corporation has not capitalized interest to the cost of assets constructed.

The estimated service lives of the various assets used in calculating amortization are as follows:

Asset	Rate
Buildings and leasehold improvements	50 – 60 years
Transmission and distribution system	15 – 50 years
Building under capital lease	20 years
Office equipment	5 – 10 years
Computer equipment and software	3 – 10 years
Plant and equipment	3 – 20 years

Contributions in aid of construction consist of third party contributions toward the cost of constructing distribution assets and may be refunded by the Corporation based on future economic evaluations, in accordance with the OEB Distribution System Code. They are accounted for as reductions to the cost of related capital assets and are amortized at rates corresponding with the useful lives of the related capital assets, until such time as they are repayable to the third party contributor.

(e) Post employment benefits other than pension

The Corporation provides its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans. The cost of these benefits is expensed as earned by employees through employment service. The excess of the net accumulated actuarial gains (losses) over 10% of the accrued benefit obligation is amortized over the average remaining service period of active employees. The expected average remaining service life of the current active group is 12 years.

(f) Regulatory environment

The *Ontario Energy Board Act, 1998 (Ontario)* ("OEBA") conferred on the Ontario Energy Board ("OEB") increased powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote residential electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors which may include, among

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment-continued

other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

Rate Setting

The electricity distribution rates and other regulated charges of the Corporation are determined in a manner that provides shareholders with a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholder's equity supporting the business of electricity distribution, which is also determined by regulation.

Rate Applications

The OEB regulates the electricity distribution rates charged by electricity distributors, such as the Corporation, using a combination of annual incentive rate mechanism ("IRM") adjustments and periodic cost of service reviews. Both such adjustments and reviews are based on applications made by the Corporation to the OEB. The current ratemaking policy of the OEB requires a cost of service review every four years, which is followed by three successive years of IRM adjustments. The OEB is currently implementing a new framework for the cost of service which will extend the review to five years.

IRM adjustments to the Corporation's distribution rates are principally formulaic in nature and based on the annual change in the Gross Domestic Product Inflationary Price Index for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

The rate adjustment resulting from a cost of service review is normally based on forecast test year data, including the amount of operating and capital expenses, debt, and shareholder's equity required to support an electricity distributor's business. The aggregate amount of debt and equity upon which an electricity distributor may recover interest charges and MARE is equal to the "rate base" of an electricity distributor, which is determined as the aggregate of its fixed assets in support of regulated electricity distribution activities and a working capital allowance.

Rates have historically, and typically, been effective from May 1st to April 30th. Accordingly, for the first four months of 2012, distribution revenue was based on rates approved for 2011.
On April 30, 2010, the OEB approved the 2010 Cost of Service Application ("Application"), with rates effective May 1, 2010. The Application allows a rate of return on debt and equity of up to 5.62% and 9.85% respectively, based on the Corporation's deemed debt (60%) and equity (40%) capital structure. The Application also resulted in the disposition of the cumulative regulatory liabilities balances as at December 31, 2008 in the amount of $7,387 over a three year period.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment-continued

Subsequently, the Corporation has filed IRM applications to adjust its distribution rates effective May 1, 2011 and May 1, 2012. As a result of such filings, the OEB approved electricity distribution rate adjustments for the Corporation of 0.18% effective May 1, 2011 and a rate rider to recover the capital costs relating to the municipal transformer station in the amount of $19,467 until April 30, 2014 and 0.88% effective May 1, 2012 with the disposition of balances for payments in lieu of taxes of $3,227 over a one-year period. In September 2012, the Corporation filed an IRM application requesting a distribution rate adjustment of .88% for 2013 rates.

Select Energy Policies and Regulation Affecting the Corporation

Smart Meter Initiative and Time of Use Electricity Distribution Rates
The Province of Ontario committed to have "Smart Meter" electricity meters installed in all homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals (Time of Use or "TOU" rates). The OEB required that TOU rates be implemented for all residential and small commercial electricity distribution customers of the Corporation by July 2011.

In December 2011, the OEB issued its "Guideline for Smart Meter Funding and Cost Recovery Final Disposition", which set out the OEB's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

On August 23, 2012, the OEB approved the Corporation's Smart Meter Prudency Application in which

i. a determination that all smart meter capital investments and operating expenditures incurred to December 31, 2011 are prudent;
ii. a rate rider to recover the difference between: a) the smart meter-related revenue requirement for 2006 through April 30, 2012 for smart meters installed through December 31, 2011; and b) the revenues collected through OEB approved smart meter funding adders through April 30, 2012; and
iii. a rate rider to recover the annual revenue requirement associated with smart meters installed through December 31, 2011, which will be in place until the implementation date for new rates as determined through the Corporation's next cost of service application.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment-continued

Green Energy Act
In 2009, the government enacted the Green Energy Act ("GEA"). This legislation made fundamental changes to the roles and responsibilities of electricity distributors in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The GEA provides electricity distributors with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. Electricity distributors will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. Electricity distributors will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

New electricity distributor License Requirements - Conservation and Demand Management Targets
On November 12, 2010, the OEB amended electricity distributor licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. The Corporation's CDM targets include a demand reduction target of 20.70 megawatts ("MW") and a consumption reduction target of 74.06 gigawatt-hours ("GWh"). Electricity distributors must also comply with a new CDM Code of the OEB, which provides electricity distributor requirements for the development and delivery of CDM Strategy to the OEB for the achievement of electricity distributor-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. The Corporation has filed its CDM Strategy with the OEB.

Other Matters
The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect future electricity distribution rates and other permitted regulatory recoveries of the Corporation.

Regulatory Accounting
In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment. The OEB has the general power to include or exclude costs, revenues, losses or gains 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. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Corporation's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The Corporation's regulatory liabilities represent costs with respect to

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Regulatory environment-continued

non-distribution market related charges and variances in recoveries that are expected to be settled in future periods.

Regulatory Liabilities
Net regulatory liabilities represent costs incurred by the Corporation and settlement variances with other participants in the electricity market, less recoveries, for the purpose of supporting the deregulation of the electricity industry in Ontario. These amounts have been accumulated pursuant to regulation underlying the Electricity Act, 1998 (Ontario) and are deferred assets or liabilities, as appropriate, in anticipation of their future recovery or repayment in electricity distribution service charges

(g) Revenue recognition and cost of power

Energy revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power consumed. Revenues from other activities are recorded when goods are delivered or services are provided.

(h) Payments in lieu of income taxes ("PILs")

Under the Electricity Act, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The Corporation accounts for PILs using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

PILs are henceforth referred to as income taxes.

(i) Impairment of long-lived assets

Generally accepted accounting principles require that an impairment loss be recognized when events or circumstances indicate that the carrying amount of the long-lived asset is not recoverable and exceeds its fair value. Any resulting impairment loss is recorded in the period in which the impairment occurs.

The Corporation has determined that there was no impairment of long-lived assets as at December 31, 2012.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(j) Financial assets and liabilities

All financial instruments are classified into one of the following categories – held-for-trading, available for sale, held-to-maturity, other liabilities or loans and receivables. All financial instruments are carried on the balance sheet at fair value, except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The company has classified its financial instruments as follows:

Cash and cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Due from related parties	Loans and receivables
Accounts payable	Other liabilities
Consumer deposits	Other liabilities
Long-term debt	Other liabilities

Derivatives and hedge accounting

The Corporation does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the preparation of these financial statements.

Financial instruments

The Corporation has adopted CICA Handbook Sections 3862 Financial Instruments Disclosures and 3863 Financial Instruments Presentation. The adoption of these standards requires the disclosure of qualitative and quantitative information about the Corporation's risks associated with recognized and unrecognized financial instruments (see Note 13).

3. INVENTORIES

The amount of inventories consumed by the Corporation and recognized as an expense during 2012 was $161 (2011 - $178).

(in thousands of dollars)

4. REGULATORY LIABILITIES

		2012		2011
Settlement of variances	$	1,108	$	2,632
Regulatory variances disposition account		(3,315)		(5,876)
Other regulatory assets		774		777
Smart Meter and stranded meter deferral		3,929		14,295
Future income taxes		(182)		(3,436)
Customer liability of future taxes		(19,352)		(18,463)
Balance, end of year	$	(17,038)	$	(10,071)

5. INCOME TAXES

		2012		2011
Accounting income before tax	$	5,138	$	4,922
Increase (decrease) in taxable income resulting from:				
Non-deductible and non-taxable items		40		35
Timing differences		(7,852)		(6,227)
Taxable income	$	(2,674)	$	(1,270)
Tax rate		26.50%		28.25%

The income taxes provision consists of:

		2012		2011
Current	$	(709)	$	(359)
Future income tax expense relating to current year change in temporary differences		1,178		1,522
Regulatory liability relating to future tax expense		377		(630)
Other miscellaneous adjustments		(132)		(557)
Income tax provision	$	714	$	(24)

(in thousands of dollars)

5. INCOME TAXES (continued)

Significant components of the Corporation's future tax balance as at December 31 are as follows:

		2012		2011
Post retirement benefits other than pensions	$	2,025	$	1,917
Plant and equipment		13,158		15,986
Regulatory liabilities		4,515		2,517
Tax reserves		193		137
Future income taxes	$	19,891	$	20,557

Future income tax rates are calculated using a 26.5% rate (2011- 25%).

6. CAPITAL ASSETS

	2012 Cost	Accumulated amortization	Net book value	2011 Net book value
Land	$ 1,648	$ -	$ 1,648	$ 1,648
Land and building under capital lease	11,689	(7,579)	4,110	4,698
Buildings and leasehold improvements	4,335	(1,456)	2,879	3,028
Plant and equipment	5,942	(3,461)	2,481	2,186
Transmission and distribution system	262,098	(92,544)	169,554	155,551
Office equipment	872	(750)	122	147
Computer equipment and software	12,659	(10,081)	2,578	1,773
Construction in progress	1,792	-	1,792	2,695
	301,035	(115,871)	185,164	171,726
Contributions in aid of construction	(41,494)	9,836	(31,658)	(30,284)
Balance, end of year	$ 259,541	$(106,035)	$ 153,506	$ 141,441

(in thousands of dollars)

7. POST EMPLOYMENT BENEFITS

The Corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. The Corporation recognizes these post-retirement costs in the period in which the employees earn the benefits, through their services. The accrued benefit liability and the expense for the year ended December 31, 2012 were based on results and assumptions determined by actuarial valuation as at January 1, 2012.

		2012		2011
Accrued benefit obligation, beginning of year	$	6,902	$	6,646
Estimated benefit expense for year		132		180
Interest expense		307		365
Actuarial gain for year		(403)		-
Benefits paid during the year		(288)		(289)
Accrued benefit obligation, end of year		6,650		6,902
Unamortized actuarial gain		991		765
Accrued benefit liability, end of year	$	7,641	$	7,667

In 2012, the amortization of the actuarial gain was $177 (2011 - $62).

The significant assumptions used are as follows (weighted average):

	2012	2011
Accrued benefit obligation as at December 31:		
Discount rate	4.50%	5.50%
Rate of compensation increase	3.00%	3.00%
Benefit cost of years ended December 31:		
Discount rate	5.50%	5.50%
Rate of compensation increase	3.00%	3.00%
Assumed health care cost trend rates at December 31:		
Initial health care cost trend rate	8.33%	9.00%
Cost trend rate declines to	4.00%	4.00%
Year that rate reaches the rate it is assumed to remain at	2025	2025

(in thousands of dollars)

8. PENSIONS

The Corporation provides a pension plan for its employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. Contributions by the Corporation were at a rate of 8.3% for employee earnings below the year's maximum pensionable earnings and 12.8% thereafter. In 2012, the Corporation made employer contributions of $1,012 to OMERS (2011 -$888).

9. CAPITAL LEASE OBLIGATION

The Corporation has a capital lease arrangement with the Town of Oakville for the head office at 861 Redwood Square. The assets under capital lease are included in Capital Assets (see Note 6). The property under capital lease is amortized on a straight-line basis over the term of the lease agreement of 20 years.

Future minimum payments under the capital lease arrangement are as follows for the year-ends:

2013	$ 1,345
2014	1,345
2015	1,345
2016	1,345
2017	1,345
2018 - 2029	16,140
	22,865
Less amount representing interest, imputed at 8.6%	(10,879)
Less current portion	(325)
Long-term portion of lease obligation	$11,661

(in thousands of dollars)

10. LONG-TERM DEBT

The Corporation had promissory notes outstanding in the amount of $67,946 (2011 - $67,946), issued effective February 1, 2000, held by the Town of Oakville, with principal repayment due on February 1, 2020. Future interest rates to be determined annually throughout the balance of the terms of the notes. At December 31, 2012 interest rates in effect were 5.87% (2011 – 5.87%)

During the year, OHEDI signed a $22,000 loan agreement with Infrastructure Ontario for a 30 year term and a fixed interest rate of 4% throughout the term of the loan. The Infrastructure Ontario debt is secured by a General Security Agreement with a second charge over all assets of OHEDI. Proceeds were used to replace working capital used in the 2010-2011 construction of a transmission station in Oakville.

Repayment of the Long term debt for the years ended December 31:

2013	$ 390
2014	406
2015	422
2016	440
2017	457
Thereafter	87,767
Total long term debt	89,882
Less current portion	(390)
Long-term debt	$89,492

11. SHARE CAPITAL

On December 19, 2011, the Corporation issued 407 common shares with no par value to Oakville Hydro Corporation for $22,000. This issuance was used in part to settle an account payable to Oakville Hydro Corporation in the amount of $14,470.

12. GENERAL LIABILITY INSURANCE

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the electrical utilities in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2012, no assessments have been made.

13. FINANCIAL INSTRUMENTS

The Corporation's fair value measurements are as follows:

Level 1

The carrying values of cash and cash equivalents, accounts receivable, consumer deposits and accounts payable approximate fair value because of the short maturity of these instruments.

Level 3

It is not practicable to determine the fair value of the long-term borrowings from the Town of Oakville due to the limited amount of comparable market information available.

The Corporation's activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

i) Credit risk

Cash and cash equivalents are held in a Canadian Chartered Bank. Financial assets carry credit risk that a counter-party will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Town of Oakville. No single customer would account for revenue in excess of 10% of total revenue.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations. The amount of the allowance for doubtful accounts at December 31, 2012 is $505 (2011 - $352).

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2012, approximately $332 (2011 - $ 211) is considered 60 days past due. The Corporation has approximately 64,808 customers, the majority of which are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2012, the Corporation holds security deposits in the amount of $4,639 (2011 - $5,169).

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Consumer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Consumer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Corporation. Interest expense of $20 was incurred on liabilities not held for trading in 2012 (2011 $24).

13. FINANCIAL INSTRUMENTS (continued)

ii) Market risk

Market risks primarily refer to the risk of loss that result from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates which is set every 4 years, the last one being 2010.

ii) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity exists to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $ 20,000 line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

(in thousands of dollars)

14. RELATED PARTY TRANSACTIONS

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts and balances with the Town of Oakville for the years ended December 31:

		2012		2011
Transactions:				
Revenue				
Energy sales	$	6,362	$	5,471
Rent		37		-
Expenses				
Interest on capital leases		1,074		1,095
Cashier services		3		4
Tree trimming services		285		197
Garage services		400		530
Property taxes		320		337
Interest on long –term debt		3,988		3,988
Balances:				
Amounts due to:				
Capital leases		11,986		12,285
Long-term debt		67,946		67,946

Included in accounts receivable reported in the balance sheet is $542 owing from the Town of Oakville (2011 - $11) relating to Energy sales and $74 (2011 - $491) relating to other receivables. Included in accounts payable reported in the balance sheet is $40 owing to the Town of Oakville (2011 - $3). These balances are non-interest bearing.

(in thousands of dollars)

14. RELATED PARTY TRANSACTIONS (continued)

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts and balances with the parent, Oakville Hydro Corporation, and its subsidiaries, for the years ended December 31:

		2012		2011
Transactions:				
Revenue				
Billing administration fee	$	699	$	685
Management fees		516		322
Other charges		302		291
Expenses				
Meter repair and related services		31		27
Corporate governance charge		10		10
Locating services from affiliate		817		640
Balances:				
Amounts due from/due to:				
Receivable from related parties		-		9,851
Payable to related parties		-		-

Included in accounts payable reported on the balance sheet is $939 owing to related parties (2011- $1,359). Included in accounts receivable reported on the balance sheet is $10 owing from related parties (2011 – $15). These balances are non-interest bearing.

15. SHORT-TERM CREDIT FACILITIES

The Corporation participates in the pooling of deposits and banking facilities with its parent company OHC and OHC's wholly owned subsidiaries. Under this arrangement, the Corporation has an uncommitted line of $20 million credit facility available with a Canadian chartered bank. As at December 31, 2012, no amount was drawn on this facility. The Corporation has a letter of credit facility available of $16 million with a Canadian chartered bank, of which $15 million has been assigned to secure its primary source of electricity as required by the Independent Electricity System Operator's Settlement Manual ("IESO")

Subsequent to year end, the letter of credit to the IESO was reduced to $10.5 million.

16. CAPITAL DISCLOSURE

The main objectives of the Corporation when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, comply with covenants related to its credit facilities, prudently manage its capital structure to recover financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2012, shareholder's equity amounts to $71,100 (2011 – $66,676) and long-term debt amounts to $89,492 (2011 - $67,946).

17. EMERGING ACCOUNTING ISSUES

a) Transition to International Financial Reporting Standards

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that would have Canadian GAAP converge with IFRS, effective January 1, 2011 which would have required entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved the incorporation of a one year deferral of IFRS into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2012. This deferral has subsequently been deferred further to annual periods beginning on or after January 1, 2015.

The amendment also requires entities that do not prepare its interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

The Corporation has decided to implement IFRS commencing on January 1, 2015.

b) Accounting for rate regulated activities under IFRS

IFRS does not currently provide guidance on accounting for the effects of rate regulation and the recognition of regulatory assets and liabilities. Currently, rate regulated entities do not recognize regulatory assets and liabilities in their IFRS compliant financial statements. The impact of rate regulated accounting has been disclosed in Note 2(f).

17. EMERGING ACCOUNTING ISSUES (continued)

b) Accounting for rate regulated activities under IFRS (continued)

IFRS 1 provides an exemption from the retroactive restatement for entities with operations subject to rate regulation. This exemption permits, at the date of transition, an entity to use the carrying values of property, plant and equipment and intangible assets as deemed cost, thus avoiding the need to restate historical balances using IFRS principles or to determine fair value. The Corporation has elected to apply this exemption for all items of property, plant and equipment and intangible assets subject to rate regulation upon the adoption of IFRS.

On July 28, 2009, the OEB issued its Report of the Board – Transition to IFRS, which contains recommendations on how regulatory reporting requirements should change in response to IFRS. The OEB has now initiated a second phase in its transition project, which involves amending certain regulatory instruments. The Corporation continues to evaluate the potential impacts of the recommendations contained in the Report of the Board on both the activities of the Corporation and its IFRS transition plan.

Consolidated Financial Statements of

OAKVILLE HYDRO CORPORATION

December 31, 2012

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Chartered Accountants
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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Oakville Hydro Corporation

We have audited the accompanying consolidated financial statements of Oakville Hydro Corporation ("the Entity"), which comprise the consolidated balance sheet as at December 31, 2012, the consolidated statements of shareholder's equity, operations and cash flows for the year then ended, and notes, comprising 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 an 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 our 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, we 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.

KPMG

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Oakville Hydro Corporation as at December 31, 2012, and the consolidated results of operations and its consolidated cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Hamilton, Canada

April 4, 2013

OAKVILLE HYDRO CORPORATION
Table of Contents
December 31, 2012

OAKVILLE HYDRO CORPORATION
Consolidated Balance Sheet
December 31, 2012
(in thousands of dollars)

	2012	2011
ASSETS		
CURRENT		
Cash and cash equivalents	$ 33,129	$ 18,542
Accounts receivable	35,056	44,473
Inventories (Note 3)	3,432	4,292
Prepaid expenses	490	424
	72,107	67,731
OTHER		
Long-term assets(Note 5)	1,500	-
Future income taxes (Note 6)	19,398	20,099
	20,898	20,099
CAPITAL ASSETS (Note 7)	169,999	151,491
INTANGIBLE ASSETS (Note 8)	7,992	4,594
	$ 270,996	$ 243,915
LIABILITIES		
CURRENT		
Accounts payable and accrued charges	$ 23,978	$ 26,314
Consumer deposits	4,639	5,169
Deferred revenue	3	41
Current portion-long-term debt (Note 12)	390	-
Capital lease obligation (Note 11)	325	299
	29,335	31,823
OTHER		
Regulatory liabilities (Note 4)	17,038	10,071
Post employment benefits (Note 9)	7,767	7,789
Capital lease obligation (Note 11)	11,661	11,986
Long-term debt (Note 12)	98,575	77,029
	135,041	106,875
	164,376	138,698
SHAREHOLDER'S EQUITY		
SHARE CAPITAL		
Authorized and issued - 2,000 common shares	63,024	63,024
RETAINED EARNINGS	43,596	42,193
	106,620	105,217
	$ 270,996	$ 243,915

See accompanying notes to the consolidated financial statements.

APPROVED BY THE BOARD

.... Director

.... Director

OAKVILLE HYDRO CORPORATION
Consolidated Statement of Shareholder's Equity
Year ended December 31, 2012
(in thousands of dollars)

	Share Capital	Retained Earnings
Balance, December 31, 2011	**$ 63,024**	**$ 42,193**
Net income	**-**	**4,203**
Dividends	**-**	**(2,800)**
Balance, December 31, 2012	**$ 63,024**	**$ 43,596**
Balance, December 31, 2010	$ 63,024	$ 39,916
Net income	-	5,077
Dividends	-	(2,800)
Balance, December 31, 2011	**$ 63,024**	**$ 42,193**

See accompanying notes to consolidated financial statements.

OAKVILLE HYDRO CORPORATION
Consolidated Statement of Operations
Year ended December 31, 2012
(in thousands of dollars)

	2012	2011
REVENUE		
Energy and distribution revenue	**$ 187,062**	$ 170,890
Cost of power	**(149,134)**	(138,130)
Net distribution revenue	**37,928**	32,760
Other revenues	**9,672**	6,718
	47,600	39,478
EXPENSES		
Personnel costs	**15,999**	14,955
Contract services	**4,337**	3,831
Property and occupancy costs	**1,244**	1,287
Material costs	**1,121**	861
Other costs	**7,494**	5,681
Costs allocated to capital assets	**(8,514)**	(8,940)
	21,681	17,675
EARNINGS BEFORE AMORTIZATION, INTEREST AND INCOME TAXES	**25,919**	21,803
AMORTIZATION	**(14,749)**	(10,973)
INTEREST	**(6,245)**	(5,943)
INCOME BEFORE INCOME TAXES	**4,925**	4,887
INCOME TAX PROVISION (Note 6)	**722**	(190)
NET INCOME	**$ 4,203**	$ 5,077

See accompanying notes to consolidated financial statements.

OAKVILLE HYDRO CORPORATION
Consolidated Statement of Cash Flows
Year ended December 31, 2012
(in thousands of dollars)

	2012	2011
NET INFLOW (OUTFLOW) OF CASH RELATED TO THE FOLLOWING ACTIVITIES		
OPERATING		
Net income	$ 4,203	$ 5,077
Items not affecting cash		
Amortization	14,749	10,973
Future taxes	1,589	944
Loss on disposal of fixed asset	117	-
Post-employment benefits	(22)	202
	20,636	17,196
Changes in non-cash working capital items		
Accounts receivable	9,417	(12,107)
Accounts payable and accrued charges	(2,336)	(10,966)
Other	630	(271)
	28,347	(6,148)
FINANCING		
Consumer deposits	(530)	161
Contribution in aid of construction	1,100	2,546
Capital lease obligation	(299)	(274)
Long term debt	21,936	-
Dividends	(2,800)	(2,800)
Net cash used in financing activities of continuing operations	19,407	(367)
INVESTING		
Deposit held in trust	(1,500)	-
Regulatory liabilities	(6,260)	(5,446)
Proceeds on disposal of capital assets	137	-
Additions to intangible assets	(3,398)	(4,625)
Additions to capital assets	(22,146)	(28,983)
	(33,167)	(39,054)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	14,587	(45,569)
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	18,542	64,111
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 33,129	$ 18,542
SUPPLEMENTAL INFORMATION		
Interest paid	$ 6,245	$ 5,919
Income taxes paid	$ (3,928)	$ 1,376
Acquisition of capital assets through non-cash capital contributions	$ 1,429	$ 1,837
Increase in regulatory liabilities for stranded meters transferred from fixed assets	$ 2,342	$ (870)
Increase in regulatory liabilities related to increase in future tax assets	$ 889	$ (996)
Increase in fixed assets for smart meters transferred from regulatory liabilities	$ 10,123	$ -
Decrease in regulatory liabilities for stranded meters transferred from inventory	$ (126)	$ -

See accompanying notes to the consolidated financial statements.

1. NATURE OF OPERATIONS

Oakville Hydro Corporation ("the Corporation") was incorporated January 28, 2000, under the laws of the Province of Ontario.

The principal activity of the Corporation and its wholly owned subsidiaries is to distribute electricity to the residents and businesses in the Town of Oakville, under the license issued by the Ontario Energy Board ("OEB") and provide energy related services to customers.

The Corporation's subsidiary, Oakville Hydro Electricity Distribution Inc. ("OHEDI") was incorporated on January 28, 2000, under the laws of the Province of Ontario and is regulated by the OEB. Changes to revenue rates and terms of operation require OEB approval. The Corporation and all other subsidiaries are considered affiliates to OHEDI and must adhere to the Affiliate Relationship Code issued by the OEB.

Activities of the Corporation, and its other subsidiaries, including Oakville Hydro Energy Services Inc., El-Con Construction Inc., Golden Horseshoe Metering Systems Inc., and Sandpiper Energy Solutions Inc., are to provide energy services, energy efficient home comfort equipment and services, utility billing services, street lighting maintenance services, retro-fit multi-residential buildings to individually metered units, utility related construction and power generation. In 2005 Oakville Hydro Energy Services Inc., obtained an Electricity Generation License from the OEB to allow it to generate electricity.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles and policies set forth in the Accounting Procedures Manual issued by the Ontario Energy Board under the authority of the Ontario Energy Board Act, 1998:

(a) Principles of consolidation

The consolidated financial statements include the accounts of Oakville Hydro Corporation and its wholly owned subsidiaries: Oakville Hydro Electricity Distribution Inc., Oakville Hydro Energy Services Inc., Golden Horseshoe Metering Systems Inc., Sandpiper Energy Solutions Inc. and El-Con Construction Inc. All intercompany transactions and balances have been eliminated.

(b) Measurement uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and note disclosures thereto. Due to inherent uncertainty in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future regulatory decisions.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(b) Measurement uncertainty - continued

Accounts receivable, regulatory assets and liabilities are stated after evaluation of amounts expected to be collected and an appropriate allowance for doubtful accounts. Inventories are recorded net of provisions for obsolescence. Amounts recorded for amortization of capital assets are based on estimates of useful service life. Post employment benefits are based on certain assumptions, including interest (discount) rates, salary escalation, the average retirement age of employees, employee turnover and expected health and dental costs.

(c) Cash and cash equivalents

Cash and cash equivalents include demand deposits held and may also include short-term investments that are readily convertible to cash without significant loss in value with a term of less than 3 months.

(d) Inventories

Inventories are stated at the lower of cost and net realizable value and consist of maintenance materials and supplies. Cost is determined on a weighted average basis. Major spare parts and standby equipment are presented as capital assets as they are used during more than one period.

(e) Capital assets

Capital assets are recorded at cost, and are amortized over their estimated service lives using the straight-line method of amortization. In the year of addition or completion, one half year of amortization is taken on the asset. Construction in progress assets are not amortized until the project is complete and in service. The Corporation has not capitalized interest to the cost of assets constructed.

The estimated service lives of the various assets used in calculating amortization are as follows:

Asset	Rate
Buildings and leasehold improvements	50 - 60 years
Transmission and distribution system	15 - 50 years
Building under capital lease	20 years
Office equipment	5 - 10 years
Computer equipment and software	3 – 10 years
Plant and equipment	3 - 20 years

Contributions in aid of construction consist of third party contributions toward the cost of constructing distribution assets and may be refunded by OHEDI based upon future economic evaluations, in accordance with the OEB Distribution System Code. They are accounted for as reductions to the cost of related capital assets and are amortized at rates corresponding with the useful lives of the related capital assets until such time as they are repayable to the third party contributor.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(f) Intangible assets

Intangible assets consist of customer contracts acquired and are recorded at cost less accumulated amortization. Amortization is calculated on a straight line basis over the estimated service life of the asset.

(g) Regulatory environment

The Corporation's subsidiary OHEDI is regulated by the OEB. The *Ontario Energy Board Act, 1998 (Ontario)* gives the OEB the power and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote residential electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to electricity distributors which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

Rate Setting

The electricity distribution rates and other regulated charges of OHEDI are determined in a manner that provides shareholders with a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholder's equity supporting the business of electricity distribution, which is also determined by regulation.

Rate Applications

The OEB regulates the electricity distribution rates charged by electricity distributors, such as OHEDI, using a combination of annual incentive rate mechanism ("IRM") adjustments and periodic cost of service reviews. Both such adjustments and reviews are based on applications made by OHEDI to the OEB. The current ratemaking policy of the OEB requires a cost of service review every four years, which is followed by three successive years of IRM adjustments. The OEB is currently implementing a new framework for the cost of service which will extend the review to five years.

IRM adjustments to OHEDI's distribution rates are principally formulaic in nature and based on the annual change in the Gross Domestic Product Inflationary Price Index for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "Stretch Factor" determined by the relative efficiency of an electricity distributor.

The rate adjustment resulting from a cost of service review is normally based on forecast test year data, including the amount of operating and capital expenses, debt, and shareholder's equity required to support an electricity distributor's business. The aggregate amount of debt and equity upon which an electricity distributor may recover interest charges and MARE is equal to the "rate base" of an electricity distributor, which is determined as the aggregate of its fixed assets in support of regulated electricity distribution activities and a working capital allowance.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(g) Regulatory environment-continued

Rates have historically, and typically, been effective from May 1st to April 30th. Accordingly, for the first four months of 2012, distribution revenue was based on rates approved for 2011.

On April 30, 2010, the OEB approved the 2010 Cost of Service Application ("Application"), with rates effective May 1, 2010. The Application allows a rate of return on debt and equity of up to 5.62% and 9.85% respectively, based on OHEDI's deemed debt (60%) and equity (40%) capital structure. The Application also resulted in the disposition of the cumulative regulatory liabilities balances as at December 31, 2008 in the amount of $7,387 over a three year period.

Subsequently, OHEDI has filed IRM applications to adjust its distribution rates effective May 1, 2011 and May 1, 2012. As a result of such filings, the OEB approved electricity distribution rate adjustments for OHEDI of 0.18% effective May 1, 2011 and a rate rider to recover the capital costs relating to the municipal transformer station in the amount of $19,467 until April 30, 2014 and 0.88% effective May 1, 2012 with the disposition of balances for payments in lieu of taxes of $3,227 over a one-year period. In September 2012, OHEDI filed an IRM application requesting a distribution rate adjustment of .88% for 2013 rates.

Select Energy Policies and Regulation Affecting OHEDI

Smart Meter Initiative and Time of Use Electricity Distribution Rates
The Province of Ontario committed to have "Smart Meter" electricity meters installed in all homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals (Time of Use or "TOU" rates). The OEB required that TOU rates be implemented for all residential and small commercial electricity distribution customers of OHEDI by July 2011.

In December 2011, the OEB issued its "Guideline for Smart Meter Funding and Cost Recovery Final Disposition", which set out the OEB's filing requirements in relation to the funding of, and the recovery of costs associated therewith, smart meter activities conducted by electricity distributors.

On August 23, 2012, the OEB approved OHEDI's Smart Meter Prudency Application in which:

i. a determination that all smart meter capital investments and operating expenditures incurred to December 31, 2011 are prudent;
ii. a rate rider to recover the difference between: a) the smart meter-related revenue requirement for 2006 through April 30, 2012 for smart meters installed through December 31, 2011; and b) the revenues collected through OEB approved smart meter funding adders through April 30, 2012; and
iii. a rate rider to recover the annual revenue requirement associated with smart meters installed through December 31, 2011, which will be in place until the implementation date for new rates as determined through OHEDI's next cost of service application.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(g) Regulatory environment-continued

Green Energy Act
In 2009, the government enacted the Green Energy Act ("GEA"). This legislation made fundamental changes to the roles and responsibilities of electricity distributors in the areas of renewable power generation, conservation and demand management delivery, and the development of smart distribution grids.

The GEA provides electricity distributors with the freedom to own and operate a portfolio of renewable power generation and will permit them to provide district heating services in their communities through co-generation. Electricity distributors will also bear added responsibilities to assist and enable consumers to reduce their peak demand and conserve energy in an effort to meet provincial conservation targets. Electricity distributors will also gain new responsibilities in transforming their local distribution networks into smart grids harnessing advanced technologies to facilitate the connection of small-scale generators and the two-way flow of information.

New electricity distributor License Requirements-Conservation and Demand Management Targets
On November 12, 2010, the OEB amended electricity distributor licenses to include requirements for achieving certain CDM targets over a four year period commencing January 1, 2011. OHEDI's CDM targets include a demand reduction target of 20.70 megawatts ("MW") and a consumption reduction target of 74.06 gigawatt-hours ("GWh"). Electricity distributors must also comply with a new CDM Code of the OEB, which provides electricity distributor requirements for the development and delivery of CDM Strategy to the OEB for the achievement of electricity distributor-specific CDM targets, annual accounting and reporting to the OEB, and eligibility criteria for performance incentive payments. OHEDI has filed its CDM Strategy with the OEB.

Other Matters
The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between the OEB and interested stakeholders, may affect future electricity distribution rates and other permitted regulatory recoveries of OHEDI.

Regulatory Accounting
In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment. The OEB has the general power to include or exclude costs, revenues, losses or gains 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. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. OHEDI's regulatory assets represent certain amounts receivable from future customers and costs that

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(g) Regulatory environment-continued

have been deferred for accounting purposes because it is probable that they will be recovered in future rates. OHEDI's regulatory liabilities represent costs with respect to non-distribution market related charges and variances in recoveries that are expected to be settled in future periods.

Regulatory Liabilities
Net regulatory liabilities represent costs incurred by OHEDI and settlement variances with other participants in the electricity market, less recoveries, for the purpose of supporting the deregulation of the electricity industry in Ontario. These amounts have been accumulated pursuant to regulation underlying the Electricity Act, 1998 (Ontario) and are deferred assets or liabilities, as appropriate, in anticipation of their future recovery or repayment in electricity distribution service charges.

(h) Post employment benefits other than pension

The Corporation provides its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans. The cost of these benefits is expensed as earned by employees through employment service. The excess of the net accumulated actuarial gains (losses) over 10% of the accrued benefit obligation is amortized over the average remaining service period of active employees. The expected average remaining service life of the current active group is 12 years.

(i) Revenue recognition and cost of power

Energy revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power consumed. Revenues from other activities are recorded when goods are delivered or services are provided.

(j) Payments in lieu of income taxes (PILs)

Under the Electricity Act, 1998, the Corporation and its subsidiaries, make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The Corporation accounts for PILs and regular corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

PILs and regular income taxes are henceforth referred to as income taxes.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(k) Impairment of long-lived assets

Generally accepted accounting principles require that an impairment loss be recognized when events or circumstances indicate that the carrying amount of the long-lived asset is not recoverable and exceeds its fair value. Any resulting impairment loss is recorded in the period in which the impairment occurs.

The Corporation has determined that there was no impairment of long-lived assets as at December 31, 2012.

(l) Financial assets and liabilities

All financial instruments are classified into one of the following categories – held-for-trading, available for sale, held-to-maturity, other liabilities or loans and receivables. All financial instruments are carried on the balance sheet at fair value, except for loans and receivables, held-to-maturity investments and other liabilities, which are measured at amortized cost.

The Corporation has classified its financial instruments as follows:

Cash and cash equivalents	Held for trading
Accounts receivable	Loans and receivables
Accounts payable	Other liabilities
Consumer deposits	Other liabilities
Long-term debt	Other liabilities

Derivatives and hedge accounting

The Corporation does not have derivatives and does not engage in derivative trading or speculative activities. Hedge accounting has not been used in the preparation of these financial statements.

Financial Instruments

The Corporation has adopted CICA Handbook Sections 3862 Financial Instruments Disclosures and 3863 Financial Instruments Presentation. The adoption of these standards requires the disclosure of qualitative and quantitative information about the Corporation's risks associated with recognized and unrecognized financial instruments (see Note 14).

3. INVENTORIES

The amount of inventories consumed by the Corporation and recognized as an expense during 2012 was $309 (2011 - $248).

(in thousands of dollars)

4. REGULATORY LIABILITIES

		2012		2011
Settlement of variances	$	1,108	$	2,632
Regulatory variances disposition account		(3,315)		(5,876)
Other regulatory assets		774		777
Smart Meter and stranded meter deferral		3,929		14,295
Future income taxes		(182)		(3,436)
Customer liability of future taxes		(19,352)		(18,463)
Balance, end of year	$	(17,038)	$	(10,071)

5. LONG TERM ASSETS

During the year the Company paid a $1,500 deposit to be held in trust for the acquisition of a run-of-the-river hydro power generating facility subject to the appropriate regulatory approvals and transfers of contracts and rights. Ownership of the facility had not transferred to the Corporation by December 31, 2012.

(in thousands of dollars)

6. INCOME TAXES

		2012		2011
Accounting income before tax	$	4,925	$	4,887
Increase (decrease) in taxable income resulting from:				
Non-deductible and non-taxable items		52		136
Timing differences		(8,751)		(7,209)
CCA recapture		14		-
Taxable income		(3,760)		(2,186)
Tax rate		26.50%		28.25%
The provision for income taxes consists of:				
Current		(994)		(618)
Future income tax expense relating to current year change in temporary differences		1,213		1,575
Regulatory liability relating to future tax expense		377		(630)
Other miscellaneous adjustments		126		(517)
Income tax provision	$	722	$	(190)

Significant components of the Corporation's future tax balance as at December 31 are as follows:

		2012		2011
Non-capital losses carried forward	$	920	$	652
Tax reserves		198		137
Post retirement benefits other than pensions		2,058		1,947
Plant and equipment		11,707		14,845
Regulatory liabilities		4,515		2,518
Future income taxes	$	19,398	$	20,099

Future income taxes are calculated using a 26.5% rate (2011 - 25%).

(in thousands of dollars)

7. CAPITAL ASSETS

	Cost	2012 Accumulated amortization	Net book value	2011 Net book value
Land	$ 4,681	$ -	$ 4,681	$ 4,623
Land and building under capital lease	11,689	(7,579)	4,110	4,698
Buildings and leasehold improvements	4,362	(1,461)	2,901	3,031
Plant and equipment	24,654	(9,360)	15,294	11,587
Transmission and distribution system	259,252	(92,544)	166,708	153,009
Office equipment	872	(750)	122	147
Computer equipment and software	12,951	(10,284)	2,667	1,885
Construction in progress	5,174	-	5,174	2,795
	323,635	(121,978)	201,657	181,775
Contributions in aid of construction	(41,494)	9,836	(31,658)	(30,284)
Balance, end of year	$ 282,141	$(112,142)	$ 169,999	$ 151,491

8. INTANGIBLE ASSETS

	Cost	2012 Accumulated amortization	Net book value	2011 Net book value
Customer contracts	$ 8,281	$ (289)	$ 7,992	$ 4,594
Balance, end of year	$ 8,281	$ (289)	$ 7,992	$ 4,594

(in thousands of dollars)

9. POST EMPLOYMENT BENEFITS

The Corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees. The Corporation recognizes these post-retirement costs in the period in which the employees earn the benefits, through their services. The accrued benefit liability and the expense for the year ended December 31, 2012, were based on results and assumptions determined by actuarial valuation as at January 1, 2012.

		2012		2011
Accrued benefit obligation, beginning of year	$	6,980	$	6,715
Estimated benefit expense for year		134		184
Interest expense		311		371
Actuarial gain for year		(401)		-
Benefits paid during the year		(288)		(289)
Accrued benefit obligation, end of year		6,736		6,981
Unamortized actuarial gain		1,031		808
Accrued benefit liability, end of year	$	7,767	$	7,789

In 2012, the amortization of the actuarial gain was $179 (2011 -$64).

The significant assumptions used are as follows (weighted average):

	2012	2011
Accrued benefit obligation as at December 31:		
Discount rate	4.50%	5.50%
Rate of compensation increase	3.00%	3.00%
Benefit cost of years ended December 31:		
Discount rate	5.50%	5.50%
Rate of compensation increase	3.00%	3.00%
Assumed health care cost trend rates at December 31:		
Initial health care cost trend rate	8.33%	9.00%
Cost trend rate declines to	4.00%	4.00%
Year that rate reaches the rate it is assumed to remain at	2025	2025

(in thousands of dollars)

10. PENSIONS

The Corporation provides a pension plan for its employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. Contributions by the Corporation were at a rate of 8.3% for employee earnings below the year's maximum pensionable earnings and 12.8% thereafter. In 2012, the Corporation made employer contributions of $1,012 (2011-$888) to OMERS.

11. CAPITAL LEASE OBLIGATION

The Corporation has a capital lease arrangement with the Town of Oakville for the head office at 861 Redwood Square. The assets under capital lease are included in Capital Assets (see Note 7). The property under capital lease is amortized on a straight-line basis over the term of the lease agreement of 20 years.

Future minimum payments under the capital lease arrangement are as follows for the year-ends:

2013	$ 1,345
2014	1,345
2015	1,345
2016	1,345
2017	1,345
2018 - 2029	16,140
	22,865
Less amount representing interest, imputed at 8.6%	(10,879)
Less current portion	(325)
Long-term portion of lease obligation	$11,661

(in thousands of dollars)

12. LONG-TERM DEBT

The Corporation had promissory notes outstanding in the amount of $77,029 (2011 - $77,029), issued effective February 1, 2000, held by the Town of Oakville, with principal repayment due on February 1, 2020. Future interest rates to be determined annually throughout the balance of the term of the notes. At December 31, 2012, the promissory notes of $67,946 (2011 - $67,946) had an interest rate in effect of 5.87% (2011-5.87%) and the promissory note of $9,083 (2011 - $9,083) had an interest rate in effect of 7% (2011-7%).

During the year, the Corporation, through OHEDI, signed a $22,000 loan agreement with Infrastructure Ontario for a 30 year term and a fixed interest rate of 4% throughout the term of the loan. The Infrastructure Ontario debt is secured by a General Security Agreement with a second charge over all assets of OHEDI. Proceeds were used to replace working capital used in the 2010-2011 construction of a transmission station in Oakville.

Repayment of the Long term debt for the years ended December 31:

2013	$ 390
2014	406
2015	422
2016	440
2017	457
Thereafter	96,850
Total long term debt	98,965
Less current portion	(390)
Long-term debt	$98,575

13. GENERAL LIABILITY INSURANCE

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the electrical utilities in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to 5 years. As at December 31, 2012, no assessments have been made.

14. FINANCIAL INSTRUMENTS

The Corporation's fair value measurements are as follows:

Level 1

The carrying values of cash and cash equivalents, accounts receivable, consumer deposits and accounts payable approximate fair value because of the short maturity of these instruments.

Level 3

It is not practicable to determine the fair value of the long-term borrowings from the Town of Oakville due to the limited amount of comparable market information available.

The Corporation's activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

i) Credit risk

Cash and cash equivalents are held in a Canadian Chartered bank. Financial assets carry credit risk that a counter-party will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Town of Oakville. No single customer would account for revenue in excess of 10% of total revenue.

The carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the related impairment loss is recognized in the statement of operations. Subsequent recoveries of receivables previously provisioned are credited to the statement of operations. The amount of the allowance for doubtful accounts at December 31, 2012 is $637 (2011 - $556).The Corporation's credit risk associated with accounts receivable is primarily related to payments in OHEDI, from its distribution customers. At December 31, 2012, approximately $332 (2011 - $211) is considered 60 days past due. OHEDI has approximately 64,808 customers, the majority of which are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2012, OHEDI holds security deposits in the amount of $4,639 (2011 - $5,169).

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Consumer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Consumer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Corporation. Interest expense of $20 was incurred on liabilities not held for trading in 2012 (2011- $24).

14. FINANCIAL INSTRUMENTS (continued)

ii) Market risk

Market risks primarily refer to the risk of loss which results from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have commodity or foreign exchange risk. The Corporation, through OHEDI, is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates which is set every 4 years, the last one being 2010.

iii) Liquidity risk

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity exists to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a \$ 20,000 line of credit and monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

(in thousands of dollars)

15. RELATED PARTY TRANSACTIONS

The following summarizes the Corporation's related party transactions, recorded at the exchange amount and balances with the Town of Oakville for the years ended December 31:

	2012	2011
Transactions:		
Revenue		
Energy sales	$ 6,362	$ 5,471
Streetlight maintenance	544	488
Construction/Locating	106	-
Rent	37	-
Expenses		
Cashier services	3	4
Tree trimming services	285	197
Garage services	400	530
Property taxes	361	354
Interest on capital leases	1,074	1,095
Interest on long-term debt	4,624	4,624
Dividends paid	2,800	2,800
Balances:		
Amounts due to:		
Accounts payable, non-interest bearing	40	3
Capital leases	11,986	12,285
Long-term debt	77,029	77,029
Amounts due from:		
Accounts receivable, non-interest bearing	858	689

16. SHORT-TERM CREDIT FACILITIES

The Corporation has an uncommitted line of credit facility available of $20 million with a Canadian chartered bank. As at December 31, 2012 no amount was drawn on this facility. In addition, the Corporation has a letter of credit facility available of $16 million with a Canadian chartered bank, of which $15 million has been assigned to secure its primary source of electricity as required by the Independent Electricity System Operator Settlements Manual ("IESO").

Subsequent to year end, the letter of credit to the IESO was reduced to $10.5 million.

17. CAPITAL DISCLOSURE

The main objectives of the Corporation when managing capital are to ensure ongoing access to funding to maintain and improve the electricity distribution system, comply with covenants related to its credit facilities, prudently manage its capital structure to recover financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver appropriate financial returns.

The Corporation's definition of capital comprises shareholder's equity and long-term debt. As at December 31, 2012, shareholder's equity amounts to $106,620 (2011 – $105,217) and long-term debt amounts to $98,575 (2011 - $77,029).

18. EMERGING ACCOUNTING ISSUES

a) Transition to International Financial Reporting Standards

The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that would have Canadian GAAP converge with IFRS, effective January 1, 2011 which would have required entities to restate, for comparative purposes, their interim and annual financial statements and their opening financial position.

In October 2010, the AcSB approved the incorporation of a one year deferral of adoption of IFRS into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2012. This deferral has subsequently been deferred further to annual periods beginning on or after January 1, 2015.

The amendment also requires entities that do not prepare its interim and annual financial statements in accordance with Part 1 of the Handbook during the annual period beginning on or after January 1, 2011 to disclose that fact.

The Corporation has decided to implement IFRS commencing on January 1, 2015.

b) Accounting for rate regulated activities under IFRS

IFRS does not currently provide guidance on accounting for the effects of rate regulation and the recognition of regulatory assets and liabilities. Currently, rate regulated entities do not recognize regulatory assets and liabilities in their IFRS compliant financial statements. The impact of rate regulated accounting has been disclosed in note 2(g).

IFRS 1 provides an exemption from retroactive restatement for entities with operations subject to rate regulation. This exemption permits, at the date of transition, an entity to use the carrying values of property, plant and equipment and intangible assets as deemed cost, thus avoiding the need to restate historical balances using IFRS principles or to determine fair value. The Corporation has elected to apply this exemption for all items of property, plant and equipment and intangible assets subject to rate regulation upon the adoption of IFRS.

18. EMERGING ACCOUNTING ISSUES (continued)

b) Accounting for rate regulated activities under IFRS(continued)

On July 28, 2009, the OEB issued its Report of the Board – Transition to IFRS, which contains recommendations on how regulatory reporting requirements should change in response to IFRS. The OEB has now initiated a second phase in its transition project, which involves amending certain regulatory instruments. The Corporation continues to evaluate the potential impacts of the recommendations contained in the Report of the Board on both the activities of the Corporation and its IFRS transition plan.

Appendix D

Board Mandate

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.

BOARD OF DIRECTORS MANDATE AND CHARTER

Mandate for the Board of Directors

Adopted: November 18, 2010
Revised: December 6, 2012

1. OBJECTIVE

The Board of Directors ("**Board**") of **OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC.** (the "**Corporation**") is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of the Corporation.

The Board has determined that it would be appropriate for the Board to adopt a written mandate describing its responsibilities and duties in relation to its oversight of the business and affairs of the Corporation.

The Board is elected by and represents Oakville Hydro Corporation and is obligated to act in the best interests of the Corporation.

2. COMPOSITION OF THE BOARD OF DIRECTORS

The Board shall consist of a minimum of three (3) and a maximum of twenty (20) members and shall serve at the pleasure of Oakville Hydro Corporation and Oakville Hydro Corporation shall elect the Board annually.

The Board Chair shall be appointed from among the Corporation's directors. The Board shall provide the Chair with a position description.

The qualifications for nomination, election and continuing service on the Board as a Director are set forth in the By-law and Shareholder Direction of the Corporation.

Members of the Board shall be entitled to receive such remuneration for acting as members of the Board as may be determined from time to time by the Board on recommendation of Oakville Hydro Corporation's Advisory and Nominating Committee upon approval of the Town of Oakville.

Board of Governors' Charter

The Board's Charter outlines how the Board of Directors will satisfy the requirements set forth in its mandate. This Charter comprises:

- Operating Principles
- Operating Procedures
- Specific Responsibilities and Duties

3. OPERATING PRINCIPLES

The Board shall fulfill its responsibilities within the context of the following principles:

3.1 Board Values

The Board of Directors will act in accordance with the Board’s policies and industry best practices as applicable.

3.2 Communications

The Chair and members of the Board expect to have direct, open and frank communications throughout the year with the Board Chair and Management, as applicable.

3.3 Board Work Plan

The Board, in consultation with the Board Chair and Management, shall develop an annual Board Work Plan responsive to the Board’s responsibilities as set out in this Charter.

3.4 Meeting Agenda

The Board meeting agendas shall be the responsibility of the Board Chair. The Corporate Secretary will develop meeting agendas in consultation with the Board Chair, Board members and assigned Management.

3.5 Board Expectations and Information Needs

The Board shall communicate its expectations to Management with respect to the nature, timing and extent of its information needs. The Board expects that written material supporting agenda items will be received from Management at least one week in advance of the meeting dates.

3.6 In Camera Meetings

At each meeting of the Board, the members of the Board shall meet at their discretion in private sessions that allow the Board to discuss matters (a) amongst themselves, and (b) with Management. Actionable items resulting from these sessions will be recorded in the minutes in accordance with Guidelines for *in camera* meetings.

3.7 Adequate Resources

In all instances where the Board Chair or the Board believes that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of external experts, the Chair shall engage the necessary experts subject to prior notice and approval of the Board. The Board shall be kept apprised of both the selection of the experts and the experts findings by the Board Chair at regular Board meetings.

The Board shall consider from time to time its resources including the adequacy of the information provided to it with respect to oversight of the Management of the Corporation and shall confer with Management with respect to its findings.

Members of the Board shall have the right, for the purpose of discharging their respective powers and responsibilities, to inspect any relevant records of the Corporation and its affiliates.

3.8 Board Self-Assessment

The Board shall annually review, discuss and assess its own performance and individual member’s performance. In addition, the Board shall annually review its role and responsibilities and complete an online Board survey. The Board shall reconsider its Mandate and Charter at least annually and report to the Governance and Risk Committee with any recommendations for change.

4. OPERATING PROCEDURES

The Board shall fulfill its responsibilities within the context of the following procedures:

4.1 Frequency and Calling of Board Meetings

The Board shall meet at least quarterly and more frequently if circumstances dictate. Meetings shall be held at the call of the Board Chair or a majority of the Directors. Notice of a meeting of the Board will be given not less than seven (7) days before the meeting is to take place.

The meetings of the Board shall ordinarily include the Secretary and shall periodically include other senior officers as may be appropriate and as may be desirable to enable the Board to become familiar with the Corporation’s management team.

4.2 Quorum

A majority of the Directors will constitute a quorum for the transaction of all matters and business before the Board. Each voting member will be entitled to one vote and the Board Chair will not have a second or casting vote in the case of an equality of votes.

4.3 Secretary of Board Meetings

Unless the Board otherwise specifies, the Corporate Secretary shall act as secretary of all meetings of the Board. In the absence of the Corporate Secretary , the Board Chair shall designate a person to act as the Secretary of the meeting.

The Corporate Secretary shall keep minutes of its meetings in which shall be recorded all actions taken by the Board. Such minutes shall be made available to Board members at their request and all such minutes shall be approved by the Board for entry in the records of the Corporation.

4.4 Chair of Board Meetings

In the absence of the Board Chair at any meeting of the Board, the Chair of the Board may delegate a Board member to perform the duties of the Chair or the Board members present may elect one among them to perform the duties of the Chair.

4.5 Minutes of Board Meetings

A copy of the minutes of each meeting of the Board shall be provided to each member of the Board within twenty (20) calendar days from the meeting date.

5. SPECIFIC RESPONSIBILITIES AND DUTIES

5.1 General Responsibilities

(a) The Board shall oversee the management and affairs of the Corporation. In doing so, the Board shall establish a productive working relationship with the President and Chief Executive Officer and other members of senior management.

(b) The officers of the Corporation, headed by the President and Chief Executive Officer, shall be responsible for general day to day management of the Corporation and for making recommendations to the Board with respect to long term strategic, financial, organization and related objectives.

(c) The roles and responsibilities of the Board are intended to primarily focus on the formulation of long term strategic, financial and organizational goals for the Corporation and on the monitoring of management performance. Without limitation, the Board shall (i) oversee management-driven strategic planning process and approve the Corporation's strategic plan, (ii) assess the principal risks of the Corporation's business and ensure appropriate systems are in place to manage such risks, (iii) select, monitor and evaluate the President and Chief Executive Officer for the Corporation and oversee succession planning at the senior management level, (iv) oversee the communications policies of the Corporation and (v) monitor the effectiveness of the Corporation's internal control and management information systems to safeguard corporate assets.

(d) The Board shall review and approve the Corporation's financial objectives, short and long-term business plans for the Corporation's businesses and monitor performance in accordance with such plans. The Board shall also approve significant capital allocations and expenditures and:

(i) transactions out of the ordinary course of business;

(ii) all matters that would be expected to have a major impact on the Town of Oakville;

(iii) the appointment of any person to any position that would qualify such person as an Officer of the Corporation;

(iv) any amendments to the Corporation's pension plan(s), and

(v) any proposed changes in compensation to be paid to members of the Board of Directors on the recommendation of the Advisory and Nominating Committee.

(e) The Board will oversee the Corporation's compliance with laws and regulations, which includes overseeing the Corporation's compliance with all applicable OEB policies and procedures.

(f) With respect to significant risks and opportunities affecting the Corporation, the Board may impose such limits on the business activity of the Corporation as may be in the interests of the Corporation and the Town of Oakville.

(g) The Board shall annually consider the skills and competencies of the Board from the perspective of determining what additional skills and competencies would be helpful to the Board. The identification of specific candidates for consideration shall be the responsibility of the Advisory and Nominating Committee which shall be guided by the findings of the Board in relation to competencies and skills.

(h) The Board will ensure that the Corporation has the appropriate policies and procedures in place to establish just and reasonable rates which are:

(i) Consistent with similar utilities in comparable growth areas and as may be permitted by the *Ontario Energy Board Act*;

(ii) Intended to enhance the value of the Corporation; and

(iii) Consistent with the encouragement of economic development and activity within the Town of Oakville.

(i) The Board will adopt prudent financial standards with respect to the affairs of the Corporation and periodically will review the Corporation’s performance as to service quality and other factors used by the OEB in setting the rates the Corporation may charge to its customers and other similar financial and regulatory prudence standards.

(j) The Board shall perform such other functions as are prescribed by law, as are assigned to the Board in the Corporation’s By-Law and as it may from time to time determine in accordance with the plenary powers of the Board.

(k) The Board shall receive at each Board meeting reports on health, safety and environmental matters as they affect the Corporation and its businesses; and (iii) an annual and interim report with respect to the Corporation’s pensions plan.

(l) The Board shall provide an orientation program for new Directors and continuing education opportunities for all Directors.

(m) The Board will review and approve the annual business plan along with the operating and capital budgets.

(n) The Board will review and approve the salary grid for management, professional and supervisory positions.

(o) The Board shall approve the selection of the external auditors and the related remuneration and terms of engagement.

(p) The Board may, from time to time, meet with the external auditors *in camera* in the absence of Management.

5.2 Senior Management

(a) The Board will approve a position description for the President and Chief Executive Officer.

(b) The Board will review with the Human Resources Committee the objectives set for the President and Chief Executive Officer and performance in relation to such objectives.

5.3 Communications

(a) The Board will annually review and approve the Corporation’s annual financial statements.

(b) The Board will periodically review the means by which Oakville Hydro Corporation can communicate with the Corporation including the opportunity to do so at the annual general meeting and communications interfaces through the Corporation’s website.

5.4 Communication Process

The Board will ensure an effective process is established and applied for the communication of initiatives between the Board, the Corporation, and external stakeholders.

5.5 Other Business

The Board will consider any other matter referred to the Board by Oakville Hydro Corporation.

6. ACCOUNTABILITY

(a) The Board Chair will report on the deliberations of the Board annually to Oakville Hydro Corporation; and

(b) The Board will review this Mandate and Charter each year at its third quarter meeting to assess its adequacy and endeavour to keep its members abreast of “best practices” and recommend changes and propose a recommended Work Plan for the next 12 months.

Appendix E

Board Orientation Process

OAKVILLE HYDRO

OAKVILLE HYDRO CORPORATION

BOARD ORIENTATION/ONBOARDING MANUAL/PROCESS

Board Orientation Manual

Board Orientation/Onboarding Manual (the "Manual") is one of the key elements to the board development process. The manual is the foundation for a committed, knowledgeable and effective Board.

As new directors are appointed, the manual should be provided at the start of their term. The manual assists them with understanding their purpose, the organization and its operations, the functions of the Board and the expectations of each Director.

The manual is developed by the Corporate Secretary in consultation with the Chair of the Board/Committees, CAO, Town of Oakville and the CEO.

The attached is a comprehensive list of items included in the board manual.

Board Orientation Process

- After the appointment of a new director and before the first Board meeting, schedule a meeting between the new Board member as well as Chair of the Board and with the key individuals in the Corporation. (Corporate Secretary)
- Provide the new Director with Board Orientation/Onboarding manual. (Corporate Secretary)
- Obtain signatures from the new Director on forms as per the Corporation's By-law and applicable acts (Consent, Confidentiality, Disclosure Questionnaire, and Indemnity). (Corporate Secretary)
- At the new Director's first Board meeting, introduce to all current Board members and Executive Management Team and discuss with the new member options for Committee involvement. (Board Chair)
- Consideration to assign a mentor Board member to work with the new Director. (Board Chair)

BOARD ORIENTATION/ONBOARDING MANUAL LIST	
ITEM	**DESCRIPTION**
A	Directors Biographies/Contact list and Committee assignments
B	Executive Management Biographies/Management Org.Chart
C	Town Council Members
D	Town Strategic Plan
E	Vision, Mission, Values and Strategic Imperatives
F	2012 Calendar of Events
G	Shareholder Direction
H	Code of Conduct
I	OHC By-law
J	Board/Committee Mandates &Chair Role Description
K	Board/Committee Annual Work plan
L	Rate Setting Process
M	Current Audited Financial Statements
N	2012 Business Plan/Budget
O	Risk Management
P	Comparator Companies
Q	Leadership Behaviours
R	Getting to know your Electricity Utility from EDA
S	Blueprint for Energy Policy in Ontario
T	Affiliate Relationships Code
U	Confidentiality Agreement/Indemnity Agreement/D&O Insurance
V	Guidelines for In Camera Meetings
W	Directors Education Program
X	Community Relations Support Policy
Y	Environment Health and Safety Policy
Z	Board Portal Information

Appendix F

Codes of Conduct

CODE OF CONDUCT FOR DIRECTORS

Section 1: GOVERNANCE GUIDELINES

1.1 Purpose

The Directors of Oakville Hydro Corporation and its subsidiaries are committed to maintaining the highest standards for ethical business conduct and carrying out their responsibilities in a manner that inspires the confidence and trust of our shareholder and community. Accordingly, the Board has adopted this Code of Conduct for Directors as a guide to achieving these goals.

1.2 Definitions

(a) "Board" means the board of directors of the Corporation.

(b) "Corporation" means Oakville Hydro Corporation and/or any of its subsidiaries.

(c) "Director" means a director of the Corporation.

(d) "Directors' Code" means this Code of Conduct for Directors.

(e) "Employee Code" means the Corporation's Employee Code of Business Conduct.

1.3 Guidelines

In performing their Board and Board Committee functions, our Directors will:

(a) Act diligently, openly, honestly and in good faith.

(b) Provide leadership in advancing the company's Vision, Mission and Values.

(c) Discharge their duties, as members of the Board and of any Board Committees on which they serve, in accordance with their good faith business judgment and in the best interests of the Corporation.

(d) Become and remain familiar with the Corporation's business and the economic and competitive environment in which the Corporation operates and understand the Corporation's principal business plans, strategies and objectives; operational results and financial condition; and relative marketplace position.

(e) Commit the time necessary to prepare for, attend (in person or telephonically, as appropriate) and actively participate in regular and special meetings of the Board and of the Board Committees on which they serve.

(f) Inform the Chair of the Board and the Chair of the Governance and Risk Committee of changes in their employment, town or city of residence, other board positions, and relationships with other business, charitable and governmental entities, and other events, circumstances or conditions that may or may appear to, interfere with their ability to perform their Board or Board Committee duties.

(g) Maintain the confidentiality of all material non-public information about the Corporation, its business and affairs.

(h) Comply with all applicable provincial and federal laws.

(i) Abide by the Employee Code as set out in section 1.4 below.

(j) Abide by all by-laws, codes, policies and guidelines approved by the Board which are applicable to Directors.

1.4 Application of the Employee Code

(1) Non-management Directors

Directors of the Corporation will be bound by and comply with all sections of the Employee Code (Appendix A), except for the following sections:

17. Political involvement and activity

24. Other employment

(2) Interpretation

Unless the context suggests otherwise, in interpreting the Employee Code as it applies to Directors:

(a) The term "Department Head" means "Committee Chair" or "Board Chair";

(b) The term "CEO" means "Board Chair";

The Employee Code is to be interpreted so as to enhance and supplement the Directors' Code. Where there is any inconsistency between the terms of the Employee Code and the terms of the Directors' Code, the terms of the Directors' Code will prevail to the extent of such inconsistency.

Section 2: Conflict of Interest Policy

2.1 Policy Statement

Directors must avoid situations where their private interests conflict with or may appear to conflict with the best interests of the Corporation or the exercise of good judgment concerning the Corporation. A conflict of interest may arise where:

(a) A Director's personal interests are or may appear to be at odds with the interests of the Corporation; or

(b) A Director, Family Member or Associate receives an improper benefit or advantage as a result of the Director's relationship with the Corporation;

(c) A Director misuses information obtained in the course of acting as a Director or exploits for personal advantage his/her position or relationships with the Corporation for personal gain.

Directors have an obligation to declare any actual, potential, or perceived conflict of interest and resolve it in favour of the Corporation as described in this Policy. This Policy has been adopted by the Board in order to ensure that Directors comply with all applicable legal requirements and follow best practices when dealing with conflicts of interest.

Certain conflict of interest rules apply to Directors under the provisions of the Ontario *Business Corporations Act* (the "OBCA"). This Policy summarizes the OBCA conflict of interest requirements in Section 2.3 below, and sets out additional best practice requirements in Section 2.4 below.

2.2 Definitions

(a) "Associate" means a natural person or Entity with whom the Director has a significant business or personal relationship.

(b) "Entity" means a sole proprietorship, partnership, unincorporated association, unincorporated syndicate, unincorporated organization, trust, or corporation and a natural person in his or her capacity as trustee, executor, administrator, or other legal representative.

(c) "Family Member" means the Director's spouse, the child or parent of the Director or of the Director's spouse, or an individual who resides in the same household as the Director.

(d) "Material Contract" means a material contract or transaction or a proposed material contract or transaction with the Corporation;

(e) "Material Interest or Relationship" means any personal activity, relationship, association, or interest that could be reasonably expected to interfere with the exercise of a Director's independent and impartial judgment, recommendation, or assessment of facts in any given circumstance.

2.3 OBCA Requirements[1]

(1) Minimum Standards

The OBCA sets out rules regarding the disclosure of conflicts of interest with which Directors must comply. The Board considers the OBCA rules to be minimum standards which are to be met in addition to the other requirements of this Policy. Under the OBCA, the disclosure procedure described below is to be followed where a Director:

(a) is a party to a Material Contract; or

(b) is a director or an officer of, or has a material interest in, any individual or Entity who is a party to a Material Contract.

The OBCA requirements apply regardless of whether the Material Contract calls for approval by the Board.

(2) Procedure to Follow

If a Director has a conflict of interest, the Director must disclose in writing to the Corporation or must request to have entered into the minutes of a meeting of the Board the nature and extent of the Director's interest. Under the OBCA, a Director must make such disclosure:

(a) at the meeting at which the Material Contract is first considered;

(b) if the Director was not then interested in the Material Contract, at the first meeting after he or she becomes so interested;

(c) if the Director becomes interested after a Material Contract is made or entered into, at the first meeting after he or she becomes so interested;

(d) if a person who is interested in a Material contract or transaction later becomes a Director, at the first meeting after he or she becomes a Director;

If the Director does not attend all or any Board meetings, or if the Material Contract does not require Board approval, the Director must disclose in writing to the Corporation or request to have entered in the minutes of meetings of Directors the nature and extent of his or her interest immediately after the Director becomes aware of the Material Contract.

A Director with any conflict of interest must not attend any part of a Board meeting at which the Material Contract is discussed and must not vote on any resolution to approve the Material Contract, except where the Material Contract:

(a) Relates primarily to his/her remuneration as a director of the Corporation; or

(b) Is a policy of insurance for the Director.

2.4 Additional Best Practice Requirements & Procedures

(1) Guidance Regarding Specific Types of Conflicts

The following describes various situations that create or may create a conflict of interest and the process that the Board has agreed should be followed in each circumstance.

(a) Perception of Conflict

[1] The summary of the OBCA Requirements in Section 2.3 is for convenience only. Reference should be made to the OBCA for more information about the statutory requirements.

A perceived conflict of interest may arise if a Director has a Material Interest or Relationship with a supplier or competitor of the Corporation, or another organization that may, or may appear to, compromise the Director's independence or ability to provide an impartial or objective decision or recommendation or assessment of facts in any circumstance that relates to the Corporation.

For a conflict to be perceived it must be visible and the Director must be aware of it. Just doing business with the Corporation is not in itself a conflict of interest for a Director unless the volume of business, or the interest or relationship is personally material to the Director or material to the Corporation. Directors are not required to do exhaustive research on all contracts or relationships of the Corporation but are expected to exercise reasonable diligence and good judgment.

Best practices with respect to managing real or perceived conflicts of interest involve three principles: awareness, written disclosure, and mitigation. As soon as a Director becomes aware of an actual or potential conflict of interest, he/she should disclose the facts of the situation and the mitigating factors or actions they believe will allow them to continue to exercise independent judgment and impartiality.

(b) Procedure to Follow

(a) Annual Procedure (the "Standard Procedure")

It is a requirement of the Board that Directors complete an annual Director Questionnaire. The Questionnaire, among other things, asks Directors to disclose directorships and other Material Interests or Relationships that are, or could be perceived to be, an actual or potential conflict of interest with their obligations as a Director of the Corporation, and the mitigating factors or actions that allow them to continue to exercise independent judgment.

The responses to the annual Questionnaire are reviewed by the Corporate Secretary against the provisions of the OBCA and the Corporation's vendor registry. The results of this review are submitted to the Governance and Risk Committee to confirm, among other things, that there are no conflicts; or if real or perceived conflicts are disclosed, to confirm acceptance of the proposed mitigating factors or actions. The conclusions of the Governance and Risk Committee are reported back to Directors by the Chair of the Committee at the first Board meeting of the year and recorded in the minutes. The disclosures are retained by the Corporate Secretary in the Corporation's Minute Book for future reference, to determine when information on any material transactions or relationships disclosed by Directors is scheduled to come before the Board and should be excluded from a Director's Board package.

(b) Supplementary Procedure

After submitting their annual Directors Questionnaire, Directors have an obligation to disclose any *new* actual or potential conflicts of interest once they become aware of them. The following supplementary procedure applies *only* if a Director's or the Corporation's situation changes, or a Director becomes aware of an actual or potential conflict, *after* delivering their annual Director Questionnaire disclosure, and if at all possible before accepting an appointment or becoming involved in a situation that may create an actual or potential conflict. This supplementary procedure is similar to the procedure employed by the Governance and Risk Committee with respect to the annual Director Questionnaire, with some discretion by the Board Chair to resolve actual or potential conflicts:

(i) As soon as a Director's situation changes or he/she becomes aware of an actual or potential conflict of interest, the Director will disclose in writing (e-mail is acceptable) to the Board Chair the facts of the actual or potential conflict of interest and, if applicable, the mitigating factors or actions that will allow them to continue to exercise independent judgment.

(ii) *[*Note: lf the Board Chair is not available, or if it is the Board Chair who has an actual or potential conflict of interest, disclosure will be made to the Chair of the Governance and Risk Committee and the references to Board Chair in the following paragraphs will mean the Chair of the Governance and Risk Committee].

(iii) The Board Chair may make an immediate determination regarding the Director's disclosure, or the Board Chair may confer with the Chair of the Governance and Risk Committee or seek additional advice if he/she believes it is necessary in order to be able to respond.

(iv) The Board Chair will respond in writing (email is acceptable) to the Director regarding the actual or potential conflict, and mitigating factors or actions if any is required. The Corporation's Secretary will retain a copy of the Director's disclosure and Board Chair's response in the Corporation's minute book. If a Director first becomes aware of an actual or potential conflict of interest only when at a Board meeting, the Director will disclose at the Board meeting the facts of the actual or potential conflict of interest and, if applicable, the mitigating factors or actions that will allow them to continue to exercise independent judgment. The Corporation's Corporate Secretary will enter it into the minutes of the meeting.

(v) If disclosure is made at a Board meeting, the Board Chair may make an immediate determination regarding the Director's disclosure and mitigating factors and actions which will be written into the minutes; or at his/her discretion, if it is appropriate, the Board Chair may defer making a Final determination until after the Board meeting and advise the Director accordingly (e-mail is acceptable). The Corporation's Corporate Secretary will retain a record of the Board Chair's response in the Corporation's minute book.

(c) Business Activity

A conflict of interest may arise if a Director engages in any other business activity, directly or indirectly, which affects the activities of the Corporation, or which is in competition with the Corporation, and which may be perceived as being in conflict with the Corporation's interests.

<u>Procedure to follow</u>: Follow the Standard Procedure.

(d) Appointments

A conflict of interest may arise if a Director engages in, or accepts an appointment or election to office in any organization or association engaged in, or expected to become engaged in, any activity which is, or is likely to be, in conflict with any activity of the Corporation, or involved as a supplier to or partner of any type with the Corporation.

<u>Procedure to follow</u>: Follow the Standard Procedure prior to accepting the appointment.

(e) Non-Profit and Professional Associations

From time to time, individual Directors may be in positions of leadership in non-profit associations where they may be viewed as a spokesperson for such groups. In such situations, the individuals should ensure that they are seen as speaking for their organization or as individuals, and not as a spokesperson or representative of the Corporation.

<u>Procedure to follow</u>: If a Director is concerned that he/she has been or may be perceived to have acted or be acting as a spokesperson or representative of the Corporation, the Director shall advise the Board Chair either verbally or in writing (email is acceptable) and the Board Chair shall determine if any steps should be taken to respond to the situation. A record of the Board Chair's conclusions shall be maintained in the Corporation's Minute Book.

(f) Vendors/Suppliers

Directors may not receive a personal benefit from an Entity which is seeking to do business or to retain business with the Corporation. It is a conflict of interest if a Director is a director, employee, lobbyist, investor, consultant (including being on a retainer, although not presently active) of a vendor or supplier (a "vendor") who is bidding on or otherwise seeking to be engaged to perform work or provide services to the Corporation if:

(a) a Director has more than a 10% financial interest in the vendor;

(b) a Director has an investment in the vendor representing more than 5% of the Director's financial worth; or

(c) a Director has an Associate or Family Member who is a director or employee of the vendor.

<u>Procedure to follow</u>: Follow the Standard Procedure.

<u>Additional Requirements:</u>

(i) A Director must refrain from voting on a resolution to approve or award business to the vendor and must be absent from the meeting during any discussion regarding the vendor (as per the OBCA).

(ii) Where a Director was a director of the vendor, the foregoing requirements shall continue to apply for six months after the Director ceased to be a director of the vendor.

(iii) Directors who have acted as a lobbyist or consultant to, or have been on a retainer with, the vendor and do not expect to be engaged by the vendor, may participate in such discussions but shall refrain from voting for a three month period following termination of the consultancy relationship or the retainer.

(g) Actions that Embarrass the Corporation

Directors shall not engage in any activity or accept any appointment which is or may be perceived to be an embarrassment to the Corporation.

Procedure to follow: If a Director has engaged, or is considering engaging, in an activity or accepting an appointment that might embarrass the Corporation, he/she shall advise the Board Chair and mutually agree upon an appropriate course of action.

(2) **Board Packages**

Based on disclosures made by Directors pursuant to this Policy and in the annual Director Questionnaire, management or the Board Chair may make the determination not to provide certain information to any particular Director on the basis that such Director may have a conflict of interest respecting the matter to which the information pertains.

The Director shall be advised by the Board Chair or management that certain information has been withheld and the reason that such information has been withheld.

(3) **Situations Not Specifically Addressed/Anticipated in this Policy**

This Policy does not contemplate all situations or circumstances that may from time to time arise. Directors are expected to use their best judgment to ensure that they deal with potential and actual conflicts of interest appropriately. If a Director is not certain if a situation requires disclosure under this Policy, the Director should seek clarification from the Board Chair or the Chair of the Governance and Risk Committee.

Procedure to follow: Issues or questions arising in connection with this Policy should be raised with the Board Chair or the Chair of the Governance and Risk Committee. A record of their conclusions will be maintained in the Corporation's Minute Book. If the Board Chair thinks it appropriate, he/she shall also advise the Board of the situation and the conclusion at the next meeting of the Board.

(4) **Responsibility**

Each Director shall abide by the standards described in this Policy, and other applicable policies, guidelines or legislation; and ensure enquiries are made if a Director knows or suspects that another Director is or may be involved in a situation that creates an actual or potential conflict of interest.

Procedure to follow: If a Director knows of or suspects the existence of a potential or actual conflict of interest in relation to any other member of the Board, he/she has the responsibility to report it to the Board Chair or the Chair of the Governance and Risk Committee.

(5) **Specific Authority To speak on Behalf of the Corporation**

Only the Board Chair or such other person as the Board Chair may authorize, may be a spokesperson for the Corporation.

Approval: Board of Directors
Date: March 31, 2011

OAKVILLE HYDRO CORPORATION

EMPLOYEE CODE OF BUSINESS CONDUCT

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OAKVILLE HYDRO

Preamble

Oakville Hydro Corporation ("OHC" or the "Corporation") strives to maintain the highest level of public confidence in all aspects of the Organization. The Corporation is also proud of its services it provides to members of the Oakville Community. Underlying all that the Corporation does and strives to do are its seven core values shown below. It is only through the commitment and effort of our staff that excellent quality of services and achievement of our core values can be maintained in this level of organization.

As the Corporation's most valuable and significant resource, our Employees are expected to demonstrate the highest standard of ethical behaviour, being above reproach, trustworthy and able to withstand public scrutiny. This requirement means we must adhere to the highest standards of personal and professional competence, integrity, and impartiality and must perform our duties in a manner that recognizes a fundamental commitment to the well being of the community.

1. Our Values

The values of an organization reflect the core set of beliefs that underlie all of the activities and behaviours in which it is engaged. Critically, these values reflect the organization's aspirations with respect to its corporate culture and objectives.

The following set of principles were developed in acknowledgement of a need to augment the ways in which OHC operates, and to reflect the ways in which OHC wishes to alter its positioning with its shareholders, customers, suppliers and communities.

Safety

OHC will strive to ensure the safety of its Employees, its customers and the communities in which it operates since each of these elements form part of the core structure of the organization.

Customer Focus

OHC will strive to develop a strong customer focus that is willing and able to satisfy the needs of each of the customer segments it targets. This emphasis will be done to increase customer bonding in recognition of the fact that its customers are changing from price and product takers to price and product choosers.

Accountability

OHC recognizes that its current stakeholders are currently unaware of the range of services and benefits provided to them by the Corporation. This, in turn, reduces clarity as to how the Corporation is able to generate its return. As a Corporation, whose main shareholder is a public entity, OHC will strive to ensure that it is accountable to its stakeholders and its shareholder for all aspects of its operations.

Innovation

The environment in which OHC operates is rapidly evolving in a manner that threatens OHC's market presence and power. In order to ensure that it is able to generate sustainable returns for its shareholder, OHC will seek new, innovative means by which to engage customers and ultimately provide them with improved customer service.

Teamwork

The success of the execution of its strategic plan is premised on OHC's ability to move forward as a unified organization. Teamwork will therefore be critical to its overall success.

Communications

Open and consistent communications both inside the organization and with our customers and stakeholders is critical to improve both the culture at OHC and the relationship with customers.

Integrity/Respect

OHC will:

- strive to ensure that its strategies and operations are conducted in a manner that serves its communities and, ultimately, its shareholder; and
- act in a manner that respects its customers increasing ability to choose, and in a manner that respects the value brought forward by its entire staff.

2. Definitions

By-law: A regulation adopted by the Corporation for the government of its Directors and the regulation of its affairs.

Confidential information: Includes information of any customer, supplier or business that works with or for the Corporation; items under litigation, personal matters, including Personal Information; items under negotiations; information supplied in support of a license or other applications etc., where such information is not part of the public domain; and information designated as confidential by the Board of Directors. Confidential information also includes the meaning of "confidential and "confidential item" as found in the current By-Law.

Board of Directors: Includes any individual elected to the Board of the Corporation or its subsidiaries.

Employee: Includes an individual employed by the Corporation, including those employed on a personal services contract, volunteers, unpaid work placements, and, for the purposes of this Code, Directors.

Family member: Means a spouse or partner of the Employee, a child or parent of the Employee of his or her spouse.

Non-Pecuniary Interest: Includes family relationships, friendships, position in associations and any other interest that does not involve financial gain or loss.

Political Activity: Includes activities to:

i. Raise and contribute money to campaigns with an aim to advance any individuals or groups interest; and
ii. Campaign for an individual, group or furtherance of any issue.

Pecuniary interest: Includes an interest that an individual may have in a matter because of a reasonable likelihood or expectation of appreciable financial gain or loss for the individual, or another person with whom the individual is associated. Such interest may include a fee, commission or other compensation paid or payable to any person or business. Associated persons include Family Members, partners and employers. Pecuniary interest also includes a direct or indirect pecuniary (monetary) interest.

Personal Information: Recorded information about an identifiable individual, and includes:

i. Information relating to the race, national or ethnic origin, colour, religion, age, sex, sexual orientation or marital or family status of the individual,
ii. Information relating to the education or the medical, psychiatric, psychological, criminal or employment history of the individual or information relating to financial transactions in which the individual has been involved,
iii. Any identifying number, symbol or other particular assigned to the individual,
iv. The personal opinions or views of the individual except if they relate to another individual,
v. The address, telephone number, fingerprints or blood type of the individual,
vi. Correspondence sent to an institution by the individual that is implicitly or explicitly of a private or confidential nature, and replies to that correspondence that would reveal the contents of the original correspondence,
vii. The views or opinions of another individual about the individual, and
viii. The individual's name if it appears with other personal information relating to the individual or where the disclosure of the name would reveal other personal information about the individual.

Corporation Assets/Property: Includes all property of the Corporation including equipment, financial assets, land, vehicles, material, documents, whether in hard or digital/electronic form, inventories, tools, electronic equipment, computers, electronic mail, internet services, information and work time.

Hotline Number: Means a telephone number, web page or email address managed by an independent service provider and available for receiving concerns from any source. The Hotline number, web or email address shall be posted on the Corporation's intranet.

Concern: Means any adverse information provided to the Corporation, whether a demand for remedial action, or a report of a suspected violation of law or Corporation policy.

Corporation: Includes Oakville Hydro Corporation and its subsidiaries.

3. Interpretation and Application

In recognition of the Corporation's core values and the importance of continuity of minimum standards in demonstrating our values, this Code of Business Conduct (the "Code") has been developed. The Code clarifies the Corporation's expectations of its Employees and re-affirms its commitment to our community, service excellence and maintaining fiscal responsibility on behalf of the public. It establishes clear and reasonable standards of conduct expected of all Employees and provides guidance in the determination of appropriate conduct in the workplace.

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The Code is a compilation of principles contained in various OHC's documents and departmental policies, plans and practices. This Code is meant to support, but not replace, the use of good judgment regarding personal and professional conduct. The absence of a specific policy or regulation does not relieve any Employee from the responsibility to exercise the highest standards in those situations.

Nothing in this Code is intended to conflict with the Corporation's obligations under various collective agreements or employment contracts. It also does not alter other rules of conduct some Employees may have as part of their professional affiliation (i.e. accountants, building officials, engineers, human resource professionals, planners, etc.). It is intended to augment and apply concurrently with those professional affiliations.

Policies referred to in the Code will take priority in the event that there is any doubt as to their consistency with the Code. In addition, the Corporation may issue corporate policies and procedures that will provide further guidance for compliance with this Code.

Individual Department Heads may, at their discretion, augment these standards with specific departmental policies to apply to individual Employees, groups of Employees or all Departmental Employees. When this is done, it shall be in writing with a copy to the President and Chief Executive Officer, ("CEO"), and to the Vice President – Customer Services and Organizational Development and will be subject to prior approval of the CEO and Vice President – Customer Services and Organizational Development before the standards will be enforced.

For a comprehensive understanding of the standards of conduct that are required it is necessary that this Code be read as a whole rather than rely on individual provisions in isolation.

4. Severability

The provisions of this Code are severable and if any provision, section or word is held invalid or illegal, such invalidity or illegality will have no affect or impair the remaining provisions, sections or words.

5. Authority

This Code is authorized by the Board of the Corporation.

Matters requiring interpretation of the Code are to be referred to the CEO and/or Vice President – Customer Services and Organizational Development.

6. Scope

This Code applies to all Employees of the Corporation and its subsidiaries.

7. Enforcement of the Code of Conduct

It is the responsibility of all Supervisors, Managers, Department Heads, and the CEO, or his or her designate, to ensure that Employees receive adequate and appropriate information about this Code along with a copy and any schedules or amendments. Supervisors, Managers, Department Heads, and the CEO shall, to the best of their ability, ensure that the Code is followed.

The CEO and Vice President – Customer Services and Organizational Development, or their designate, will also review the Code on a regular basis at least once every four (4) years, to ensure that it continues to reflect the needs and responsibilities of the Corporation's Employees and administration.

Each Employee shares the obligation of ensuring compliance with the Code. They are required to address any situations of existing or potential non-compliance with the Code that they suspect or become aware of. For further information on the escalation procedures please see Section 25 below.

8. Non-Compliance

A violation of the Code may result in, but is not limited to, any one of the following responses:

i. Coaching;
ii. Verbal or written warnings;
iii. Suspension with or without pay;
iv. Dismissal for just cause;
v. Removal from volunteer positions with the Corporation;
vi. Notification sent to professional associations; and/or
vii. Such other action or penalty as may be appropriate or permitted by law under the circumstances.

The appropriate response for non-compliance with the Code shall, in the normal course, be determined by the Department Head or, in situations where the alleged violation has been committed by the Department Head, by the CEO, or his or her designate.

9. Corporate Responsibility

The Corporation will support Employees in understanding their individual and collective roles in adhering to the Code.

10. Personal Responsibilities and Obligations

Compliance with the Code is a condition of employment. It has been designed to promote compliance with numerous laws and regulations that apply to Employees working at the Corporation. With this goal in mind, we have outlined the following general expectations. Everyone must strive to:

i. Uphold laws of all levels of government, and avoid situations where they may become a party to a breach, evasion or subversion of the law;

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ii. Conduct themselves in a manner that promotes the Corporation's reputation and ensures continued confidence in the Corporation's management;
iii. Treat all persons honestly and fairly, and with proper regard for their rights, entitlements, duties and obligations, and at all times act responsibly in the performance of their duties;
iv. Be professional and courteous with their fellow Employees and the public and resolve any work related disagreements in a mature manner, based on reasonable expectations;
v. Advance the common good of the community;
vi. Carry out their duties in a fair, impartial, and transparent manner;
vii. Promote the health and safety of others;
viii. Avoid using their position improperly for personal advantage;
ix. Avoid using insider information, internal protocols or procedures for personal gain;
x. Resolve any conflict between personal interests and public duty in favour of the public interest; and
xi. Ensure that they take all steps to ensure that Personal Information and Confidential Information obtained in the course of their employment or office is safeguarded and protected in accordance with applicable laws.

It is management's responsibility to administer and enforce the Code and to demonstrate by example the obligations under this Code. It is also the duty of management to investigate suspected violations and apply the appropriate response. Management must treat Employees in a fair and equitable manner.

We ask that Employees commit to uphold the values of our Code by confirming in writing on an annual basis that they have been given a copy of the Code, have read, and understood the Code.

11. Behaviour and Professionalism

Corporation's Employees interact with clients in receipt of services or programs, community agencies, contractors, suppliers, and the general public on a daily basis. It is through our professionalism, courtesy and objectivity in these interactions that we can all ensure we achieve respect for one another.

Our Employees are viewed as ambassadors of the Corporation and are expected to reflect a professional image at all times, whether on or off duty. We do this by being conscious of the Corporation's public duty and by conducting ourselves with the highest degree of moral and ethical behaviour and integrity. This is also particularly important when the Employee is wearing a Corporation uniform, if any, or any item of clothing with the Corporation's logo, including outerwear. Employees are not permitted to wear Corporation designated uniforms outside of working hours at personal events or events unrelated to their official duties with the Corporation.

Employees must also be professional and courteous with one another. Improper behaviour in the workplace has a negative effect on others and the public. Examples of improper behaviour include excessive noise, inappropriate office decorations, potentially offensive pictures and jokes, profanity, demonstrating little or no respect for personal belongings, and engaging in conduct or behaving in such a way as to negatively impact the Corporation's reputation.

12. Workplace Safety

Workplace safety is a shared responsibility of all Corporation Employees. Managers are responsible for ensuring that Employees are aware of any potential work hazards, are trained in safe work practices and comply with the Occupational Health & Safety Act and the Workplace Violence & Harassment Act of Ontario. All Employees are to take every reasonable and necessary precaution to ensure their personal safety and health as well as that of their colleagues.

At any function or event sponsored by the Corporation at which alcohol is served, all applicable laws and the Corporation's applicable policies and procedures must be adhered to.

13. Use of Corporation Property

Corporation property should only be used by an Employee to perform work related duties and responsibilities or for community activities which are supported by the Corporation.

Corporation assets/property are to remain on Corporation's property at all times unless it is necessary to take the items off site in order to perform the Employee's job. Where Corporation's assets/property are in the care of an Employee, the items must be protected and kept secure at all times.

The Corporation's electronic networks are corporate assets and Employees must be aware that communications over the Corporation's electronic networks are not to be considered private communications (See Computer and Technology Acceptable Use Policy).

An Employee must not under any circumstances, misuse funds, property or other Corporation assets/property or knowingly assist another person to do so. The intellectual property rights in any work produced by an Employee in the course of employment at the Corporation are the exclusive property of the Corporation. In addition, software piracy, defined as using any unlicensed copy of a software package that has not been purchased for Corporation purposes, is prohibited. This provision includes taking a copy of a licensed software package for personal use or passing a copy on to another person for their use.

Upon departure from employment all Corporation intellectual property including drawings, correspondence, documents and all other Corporation assets/property which are in the individual's possession or control, will be returned to the Corporation, unless otherwise purchased from the Corporation. With written consent from their direct Manager, Employees may retain samples of their work.

14. Insider Information

Employees may sometimes be privy to confidential information and personal information concerning the affairs of the Corporation, Employees, elected officials or members of the community. The Employees are not to discuss or pass on insider information unless the exchange is necessary for a specific business purpose of the Corporation. Adherence to this practice will reduce the chances of inadvertent releases of information.

15. Confidential Information/Personal Information

Many Employees will have access to Confidential Information and Personal Information by reason of their duties and responsibilities with the Corporation. Employees must all respect such information and must ensure it is safeguarded from unauthorized disclosure or access. Such information must be protected from any unauthorized disclosure in accordance with this Code and in accordance with the provisions of the *Municipal Freedom of Information and Protection of Privacy Act*. Confidential Information and Personal Information may only be used or transmitted in order to permit the Employee to perform the duties and responsibilities associated with his or her position and where disclosure is necessary and proper in the discharge of the Corporation's functions.

Where an Employee is unsure whether the information is confidential or personal, and before making any release, please contact your Manager or the appropriate Department Head who will then determine whether such information is confidential and/or refer the matter to Vice President – Customer Services and Organizational Development or CEO.

16. Media Relations

The media play an important role in providing the public with news and information about the Corporation, and in reporting on the public views and opinions of the Corporation. Media inquiries should be referred to CEO who will respond directly on behalf of the Corporation. If a message is received from a reporter, departments will notify CEO in a timely manner to accommodate publication deadlines.

17. Political Involvement and Activity

i. Running for Public Office

Employees may exercise their civic right to run for public office, in accordance with legislative requirements.

Where an Employee wishes to run for public office, he or she may seek an unpaid leave of absence for the period between the day the Employee is nominated and ending on voting day. If the Employee is elected, he or she will resign from the Corporation immediately before taking his or her elected public office.

ii. Involvement in Political Campaign

Employees are entitled to exercise their right to support or be involved in the political campaign of a municipal, provincial or federal candidate or party, provided they do so on personal time and do not hold themselves out as representative of the Corporation. However, Employees must be and appear to be politically neutral in their official duties in order to sustain public trust in the Corporation.

Employees are permitted to participate in Electioneering, canvassing or actively work in support of a political candidate or party provided they do so outside of normal working hours, or during an authorized leave of absence without pay for this purpose, by using lieu time, adjusted work week time, float day or vacation time in accordance with any applicable collective agreement or policy requirements. Such activity must be as a citizen and not as, or appear to be as a representative of the Corporation. Examples of campaigning include telephone and e-mail solicitation, distribution of brochures, the display of campaign signs and the wearing of candidate buttons.

To maintain a positive public opinion of the Corporation, subject to any prevailing legal rights such as the Canadian Charter of Rights and Freedoms, Employees are expected to avoid expressing their personal views on matters of political controversy or on Corporation policy or administration if the comment is likely to impair public confidence in the Corporation. If there is any doubt about whether a statement is appropriate, Employees should contact their Managers for further discussion.

iii. Membership on Boards or Committees

The Corporation encourages Employees to take part in community activities. However, it is important to bear in mind that such service may, at times, place the individual in a real or perceived conflict of interest situation. As a member of a community board or external committee, the Employee must continually assess their involvement and expected decision-making responsibilities in light of their employment with the Corporation. It may be necessary to resign from a board or committee if that body has a direct role with the Corporation.

To ensure the existence and appearance of objectivity, Employees should not participate in decisions or votes that would create, or be seen to create, a conflict of interest as outlined in section 22 of this Code.

iv. Political Contributions

Employees must not use Corporation funds, goods, services, or Corporation Assets/Property to make political contributions.

18. Hiring Family Members

In general, the fact that a potential Employee is related to an existing Employee neither prejudices nor advances that person's hiring prospects, where the new Employee will not be supervised directly or indirectly by the related Employee.

19. Work of a Personal Nature

Employees in positions of authority shall not ask or require other Employees to perform work of a personal nature.

20. Professional Conduct

Employees are expected to maintain a standard of integrity above challenge in all business relationships both inside and outside the Corporation. All business relationships, including those with suppliers, contractors and consultants, must be kept at arms length so as not to create an impression of impropriety.

21. Product Recommendation

Employees will not recommend specific brand name products, services or suppliers in their capacity as Employees of the Corporation or in circumstances where it might be inferred that the Corporation had endorsed such products, services or suppliers.

22. Conflicts of Interest

Even the slightest impression of impropriety or conflict of interest can have a devastating effect. Employees are encouraged to familiarize themselves with the types of situations that could give rise to a perception of a conflict of interest and to handle themselves accordingly. The avoidance of actual and perceived conflicts of interest is essential to ensuring we fulfill our obligations to the public and each other. Employees must report any real, potential or perceived conflict of interest situation to their Manager.

Conflicts of interest must be reported, in writing, by completing the attached Notification Form (Appendix A), and the matter will be referred as necessary.

A conflict of interest may exist, for example, where an Employee or his or her family member has a pecuniary interest or non-pecuniary interest in a contract or proposed contract with the Corporation, interest in a property matter, and where the Employee may or may be seen to influence the decision made by the Corporation with respect to the contract.

Similarly, a conflict may exist where the Employee could influence the decision made in the course of performing his/her job duties, and also where he or she could influence the decision through exerting personal influence over the decision-maker, which results or appears to result in:

i. an interference with the impartial exercise of an Employee’s duties and responsibilities for the Corporation; or
ii. a gain or an advantage by virtue of an Employee’s position with the Corporation.

Some common examples of areas of potential conflicts of interest include the following:

a) A personal bid is made on the sale of Corporation property or goods, except those bids disposed of at public auction;
b) Employees engage in private employment or render services for any person or company that has or may have business dealings with the Corporation;
c) Using one's position or knowledge to influence an approval process for direct or indirect personal gain. The choice of suppliers of goods and services to the Corporation must be based on competitive considerations of quality, price, service and benefit to the Corporation, and must comply with its policies. Contracts must be awarded in a fair and legal manner and are subject to the established *Purchasing policies;*
d) Where Employees or their family members sell goods, materials or services to the Corporation without prior express written approval by CEO or his or her designate; and
e) Any conduct which may interfere with the best interests of the Corporation or the independent exercise of judgment.

In general, Employees should consider all of the following factors in making business decisions:

- Is this legal?
- Is this fair, ethical and moral?
- Would the Corporation's reputation be negatively impacted if this situation became public knowledge?
- Would members of the community, fellow Employees or third parties perceive this situation as a conflict of interest?

If a potential conflict exists the individual must advise their Manager, Department Head, Vice President – Customer Services and Organizational Development, CEO, or their designate of the situation. Please see Appendix "A".

23. Gifts and Benefits

i. Acceptance of Gifts and Benefits

In order to preserve the image and integrity of the Corporation, gifts and benefits are not to be accepted. This general prohibition on accepting gifts exists whether or not it was solicited or offered by an individual or business.

ii. Exceptions

The Corporation recognizes that moderate hospitality is an accepted courtesy of a business relationship. Accordingly, incidental gifts, hospitality or other benefits associated with an individual's official duties and responsibilities may be accepted provided that such hospitality or other benefits:

a. are appropriate, a common expression of courtesy or within the normal standards of hospitality;
b. do not put the recipients in a position where they may be or be seen by others to have been influenced in making a business decision as a result of accepting such benefits;
c. the frequency and scale of benefits accepted should not be greater than the Employee's Department Head would allow to be claimed on an expense account if it were charged to the Corporation;
d. would not compromise the integrity of the Corporation; and
e. the Department Head or CEO, or their designate are notified of the receipt of any and all gifts or benefits.

The Corporation recognizes that from time to time gifts will be donated for special Corporation events or charitable events. This practice may be reasonable provided that the gifts are publicly acknowledged and approved by the Department Head and/or CEO, or their designate in advance of the receipt of the donated gift. Approval must be obtained using the attached Notification Form (Appendix A).

iii. Hospitality Extended

The occasional hospitality for entertainment for business contacts may occur. Such practice may be acceptable provided it can be shown that the interests of the Corporation will be advanced. Such activities must be moderate and reasonable, both in cost and nature, with Corporation participants being fully aware of the business aims involved and provided that at all times the image and integrity of the Corporation are protected.

In all cases regarding Employees, the Employee's Department Head or CEO, or their designate must be notified in advance of participating in such business hospitality and/or business.

In all cases, Employees should ask themselves:

- Would I be uncomfortable disclosing this gift/benefit/hospitality to my manager?
- Is the gift/benefit/hospitality being offered to me in exchange for a favour or benefit?

24. Other Employment

Employees work hard and are dedicated to ensuring the Corporation's success in meeting its goals in the community. To ensure continued commitments to service levels, Employees are expected to avoid other employment, business activity or other undertakings:

i. while on duty;
ii. that interferes with the performance of his/her duties for the Corporation;
iii. that creates a conflict of interest (see Section 22 of this Code);
iv. that is in conflict with a by-law, policy, plan or objective of the Corporation or that is in anyway contrary to the interests of the Corporation; or
v. from which the individual derives some form of benefit by virtue solely of his/her employment with the Corporation.

Other employment means working for another employer, or being self-employed, or working for charitable or volunteer organizations which results in receiving or being eligible to receive profit, payment of compensation or other benefit from that employer or charity. If the individual is unsure as to whether or not the carrying out of any other employment, business activity or other undertaking would create an interference, conflict or improper benefit, the individual must seek guidance from his or her Manager, Department Head or CEO, or their designate.

Examples of inappropriate forms of other employment may include, but are not limited to, situations similar to the following:

- An Employee holds a real estate broker's licence. He/she makes or receives calls from clients or escorts clients on site visits during his/her normal working hours.
- Although, in his/her capacity as an Employee, an Employee has occasional dealings with a local contractor, the Employee seeks to act as a subcontractor to that contractor.

- An Employee who works late into the evenings on a second job consistently arrives late at his / her job with the Corporation and/or his or her performance is below the acceptable level.
- An Employee absent from work on an approved leave of absence and engages in work unrelated to the purpose for the leave.

25. Report on Employee Concerns or Violations of the Code

The Corporation fosters a workplace conducive to open communication regarding the Corporation's business practices. In an effort to further this commitment, this section establishes guidance for the receipt, retention and treatment of verbal or written reports received regarding accounting, internal controls, auditing matters, disclosure, fraud, violation of this code and unethical business practices. It also establishes guidance for providing Employees a means to make reports in a confidential manner.

The purpose of this section is to:

- Provide a mechanism for Employees to raise and document concerns related to accounting, internal controls, auditing matters, disclosure, fraud, violation of this Code and unethical business practices;
- Ensure Employees feel confident in raising serious concerns and to question and act upon concerns about practice;
- Provide avenues to raise those concerns and receive feedback on any action taken;
- Ensure Employees receive a response to concerns and are aware of how to pursue them if not satisfied; and
- Reassure and protect an Employee from possible reprisals or victimization.

This section does not apply to concerns over personal performance assessment between a manager and an Employee.

Where an Employee has a concern or a suspected violation of this Code occurs, a concern shall be made, verbally or in writing by calling the hotline number or using the attached Notification Form (Appendix A), to the Vice-President of Customer Services and Organizational Development or CEO or their designate or in the case of the CEO, to the Advisory and Nominating Committee or Board Chair.

26. Freedom from Reprisal

All suspected concerns or violations under Section 25 and this Code will be taken seriously and addressed promptly, discreetly and professionally. All Employees will be guaranteed freedom from reprisal, harassment or other discriminatory practice as a result of exercising their obligation to report a breach or suspected breach under any section of this Code, subject to Section 27.

When a suspected violation of this Code is reported and an investigation is initiated:

i. The identity of the reporting individual will be kept confidential, except as permitted or as may be required by law.
ii. Retaliation will not be tolerated where reporting of a suspected violation of the Code is made in good faith.
iii. If retaliatory action occurs, the Employee should report the action to their Manager, Department Head, Vice President – Customer Services and Organizational Development or CEO, or their designate.
iv. Anonymous concerns are not acceptable. Employees, who knowingly file misleading or false reports, or reports without a reasonable belief to truth or accuracy, will not be protected by this provision and may be subject to discipline, and will receive the appropriate response in accordance with Section 8 and/or the relevant terms of a collective agreement and may also be prosecuted criminally, and/or subject to civil proceedings.

27. Treatment of Concerns or Violations of the Code

All concerns or violations of the Code shall be treated as confidential. Complaints received by hotline number shall be initially summarized by the independent service provider who shall direct them to Vice President – Customer Services and Organizational Development and CEO for handling. All concerns or violations of the Code received by the Corporation shall be referred to the Chair of the Human Resources Committee and, in case of financial matters, to the Chair of the Finance and Audit Committee.

When such concerns or violations are brought forward, the issues will be treated seriously and in confidence and will be investigated within five (5) business days from the date the concern or violation has been reported as mentioned in Section 25 of this Code.

In all cases, the Vice President – Customer Services and Organizational Development shall be promptly notified of actual or suspected breaches of the Code.

The Vice President – Customer Services and Organizational Development shall:

i. Conduct an investigation of any concern as considered appropriate in the circumstances;
ii. Retain for a period of seven years any documentation received or created in connection with any concern of this Code in secured files and only the named parties shall have access to the files;
iii. Report to the Human Resources Committee / Finance and Audit Committee, as the case may be, on all concerns received; and
iv. Recommend to the Human Resources Committee / Finance and Audit Committee, as the case may be, the course of action (based on investigation) considered appropriate with respect to any concern.

The Human Resources Committee / Finance and Audit Committee shall:

i. Require the Vice President – Customer Services and Organizational Development to report at each meeting of the respective Committee on all concerns received since the date of the last such report;
ii. Consider recommendations by the Vice President – Customer Services and Organizational Development with respect to any action to be taken with respect to a concern;
iii. Determine and authorize the appropriate action that should be taken with respect to any concern; and
iv. Refer the concern to the Board for resolution.

28. Revisions

Board may, in its discretion and through a resolution of Board, augment or amend the Code.

APPROVED by the Board of Oakville Hydro Corporation on the 31st day of March, 2011.

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Appendix A

EMPLOYEE CODE OF BUSINESS CONDUCT NOTIFICATION FORM

(For notification of concern, conflict of interest or receipt of donated gift or benefit.)

Employee's Name: ____Date: ______________________

Position: ______________________________________ Department: _______________________________

Employee's Immediate Department Head: ____

Employee's Exempt Supervisor: ____

Details of concern, conflict of interest, question of conflict of interest or receipt of donated gift or benefit. If more space is needed please utilize the back of this Form:

Employee's Signature: ______________________________ Date: __________________________________

Action taken by Vice President – Customer Services and Organizational Development:

Vice President – Customer Services and Organizational Development's Signature:____________________
Date:______________________________

Noted by President & CEO: ____

President & CEO's Signature: _____________________________Date: _____________________________

Noted by HR Chair / FA Chair / Board Chair: ____

Chair's Signature: _____________________________________ Date: _____________________________

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Appendix B

EMPLOYEE CODE OF BUSINESS CONDUCT

ACKNOWLEDGMENT FORM

I, ____, acknowledge that I have received a copy of the Oakville Hydro Corporation's Code of Business Conduct. I have read and understand the provisions of the Code. I acknowledge that I must comply with its provisions and any revision that is made to it and understand that I am expected to comply with this Code.

Signature: __________________________

Printed Name: _________________________

Witnessed By:__________________________

Date: _________________________________

Appendix G

Committee Mandates

OAKVILLE HYDRO CORPORATION

FINANCE AND AUDIT COMMITTEE MANDATE AND CHARTER

<u>The Board's Mandate for the Finance and Audit Committee</u>

Adopted: January 27, 2011
Revised: December 6, 2012

The Board of Directors (the "**Board**") of **OAKVILLE HYDRO CORPORATION** is responsible for overseeing and monitoring all significant aspects of the management of the, business and affairs of Oakville Hydro Corporation and its affiliates (collectively, the "Corporation"). With respect to Oakville Hydro Electricity Distribution Inc. ("OHEDI"), this responsibility is shared with the Board of Directors of OHEDI.

MISSION STATEMENT

The Finance and Audit Committee's mission is to assist the Board in fulfilling its obligations by overseeing and monitoring the Corporation's financial accounting and reporting process and the integrity of the Corporation's financial statements and its internal control over financial reporting and the external audit process. To fulfill this mission, the Finance and Audit Committee has received this mandate and has been delegated certain authorities that it may exercise on behalf of the Board.

1. FINANCIAL REPORTING OBJECTIVE

Financial reporting and disclosure constitutes a significant aspect of the management of the business and affairs of the Corporation. The objective of the Board's monitoring of the Corporation's financial reporting and disclosure (Financial Reporting Objective) is to gain reasonable assurance that:

(a) the Corporation complies with all applicable laws, regulations, rules, policies and other requirements relating to financial reporting and disclosure, including those of the Ontario Energy Board ("OEB");

(b) the major accounting principles and policies, significant judgments and disclosures which underlie, or are incorporated in the Corporation's financial statements, are the most appropriate in the prevailing circumstances;

(c) the Corporation's financial statements present fairly the Corporation's financial position and performance in accordance with CGAAP and the policies of the OEB and constitute a fair presentation of the Corporation's financial condition; and

(d) appropriate information concerning the financial position and financial performance of the Corporation is disseminated to the Board and all other stakeholders in a timely manner.

The Board has established a committee of the Board, known as the Finance and Audit Committee (the "Committee"). This Committee has developed this Charter, which, inter alia, describes the activities in which the Committee will engage for the purpose of gaining reasonable assurance that the Financial Reporting Objective is being met.

2. FINANCIAL MANAGEMENT OBJECTIVE

The objective of the Committee is to gain reasonable assurance that:

(a) there is appropriate fairness and transparency in financial reporting;

(b) operating and capital budgets are appropriate to the needs of the Corporation;

(c) there is proper control over assets and liabilities ; and

(d) an appropriate review of operating statements is conducted by Management in a timely manner.

3. COMPOSITION OF THE COMMITTEE

The Committee shall be appointed annually by the Board and consist of a minimum of three members and a maximum of five members, with a majority being members of the Board. The Board Chair, the President and CEO and the CFO shall be non-voting ex-officio members. The Committee Chair and the members of the Committee shall be nominated by the Advisory and Nominating Committee, and approved by the Board. The Chair shall be a Board member. The Committee may appoint ad-hoc non-voting members to the Committee, as required, to assist the Committee in fulfilling its mandate.

4. RELIANCE ON MANAGEMENT AND EXPERTS

In contributing to the Committee discharging its duties under this Charter each member of the Committee shall be entitled to rely in good faith upon financial statements of the Corporation represented to him or her by Management of the Corporation or in a written report of the external auditors on the fair presentation of the financial position of the Corporation in accordance with CGAAP and any report of a lawyer, accountant, or other person whose profession lends credibility to a statement made by any such person.

Good faith reliance means that the Committee member has considered the relevant issues, questioned the information provided and assumptions used and assessed whether the analysis provided by Management or the expert is reasonable. Generally, good faith reliance does not require that the member question the honesty, competency and integrity of Management or the expert unless there is a reason to doubt their honesty, competency and integrity.

5. LIMITATIONS ON THE COMMITTEE'S DUTIES

In contributing to the Committee's discharging of its duties, each member of the Committee shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this charter is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to gain reasonable assurance, but not to ensure, that its Financial Reporting Objective and Financial Management Objective are being met and to enable the Committee to report thereon to the Board.

FINANCE & AUDIT CHARTER

The Committee's Charter outlines how the Committee will satisfy the requirements set forth by the Board in its Mandate. This Charter comprises:

- Operating Principles
- Operating Procedures
- Specific Responsibilities and Duties

6. OPERATING PRINCIPLES

The Committee shall fulfill its responsibilities within the context of the following principles:

6.1 Committee Values

The Committee members will act in accordance with the Board's policies and industry best practices, as applicable.

6.2 Communications

The Chair and members of the Committee expect to have direct, open and frank communications throughout the year with assigned Management, the Board Chair, other Committee Chairs, the external auditors, the internal auditors, and other key Committee advisors, as applicable.

6.3 Financial Literacy

All Committee members shall be financially literate, which shall mean that they have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements. The role of the Committee can only be fulfilled if its members are well informed. A process of continuing education shall be maintained that includes briefings and information on emerging issues and risks.

6.4 Work Plan

The Corporate Secretary in consultation with the Committee, Board Chair and Management, shall develop an annual Committee Work Plan responsive to the Committee's responsibilities as set out in this Charter.

The Committee will review its annual work plan at its third quarter meeting in each fiscal year. In addition, the Committee, in consultation with assigned Management, the Board Chair, the external auditors, and the internal auditors shall develop and participate in a process for review of significant accounting and reporting issues, including complex or unusual transactions and other areas that have the potential to impact the Corporation's financial disclosure.

6.5 Meeting Agenda

The Committee meeting agendas shall be the responsibility of the Committee Chair. The Corporate Secretary will develop meeting agendas in consultation with Committee Chair, Committee members, assigned Management, Board Chair, the external auditors, and the internal auditors as applicable from time to time.

6.6 Committee Expectations and Information Needs

The Committee shall communicate its expectations to assigned Management, the external auditors, and the internal auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written material supporting agenda items will be received from assigned Management, the external auditors, and the internal auditors at least seven days in advance of meeting dates. The President and CEO and the CFO are required to attend the meetings of the Committee. The Committee Chair may request the attendance of other Corporation Officials.

6.7 External Resources

To assist the Committee in discharging its responsibilities, the Committee may, in addition to the external auditors and the internal auditors, at the expense of the Corporation, retain one or more persons having special expertise.

6.8 In-Camera Meetings

At each meeting of the Committee, the members of the Committee shall meet at their discretion in private sessions that allow the Committee to discuss matters (a) amongst themselves, (b) with Management, (c) with internal auditor and (d) with external auditors. Actionable items resulting from these sessions will be recorded in the minutes in accordance with Guidelines for *in camera* meetings..

6.9 The External Auditors

The external auditors shall be accountable to the Board through the Committee. The external auditors shall report on all material issues or potentially material issues to the Committee.

6.10 The Internal Auditor

The internal auditor shall be accountable to the Board through the Committee. The internal auditor shall report on all material issues or potentially material issues to the Committee.

6.11 Access to Carry Out Committee's Duties

The Committee working in consultation with the CFO shall be given full access to the Corporation's internal accounting staff, Management, other staff, external auditors, and internal auditors as necessary to carry out the Committee's duties. While acting within the scope of its stated purpose, the Committee shall have all the authority of, but shall remain subject to, the Board.

6.12 Adequate Resources

The Committee should have adequate resources to discharge its duties as mentioned in this mandate subject to prior budget provision. Members of the Committee shall be entitled to receive such remuneration for acting as members of the Committee as the Board may determine from time to time consistent with its remuneration policies for all Board and Committee members. In all instances where the Committee believes that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of external experts, the Chair shall engage the necessary experts subject to prior notice and approval of the Board. The Board shall be kept apprised of both the selection of the experts and the experts findings through the Committee's regular verbal reports by its Chair at regular Board meetings.

7. OPERATING PROCEDURES

(a) The Committee shall annually review, discuss and assess its own performance and individual member's performance as part of Board self assessment process. In addition, the Committee shall annually review its role and responsibilities, as set out in this Charter.

(b) The Committee shall meet at every quarter, or more frequently as circumstances dictate. Meetings shall be held at the call of the Committee Chair or upon the request of two members of the Committee, or the Management or at the request of the internal auditors or external auditors. The request to be made to the Chair of the

Committee and the Chair of the Committee may determine the necessity of the meeting.

(c) A quorum shall be a majority of the voting members of the Committee. Each voting member will be entitled to one vote and the Committee Chair will not have a second or casting vote in the case of an equality of votes. No Proxies shall be permitted.

(d) Unless the Committee otherwise specifies, the Corporate Secretary, shall act as Secretary of all meetings of the Committee. In the absence of the Corporate Secretary the Chair of the Committee shall designate a person to act as the Secretary of the meeting.

(e) In the absence of the Chair of the Committee at any meeting of the Committee, the Chair may delegate a Committee member to perform the duties of the Chair or the Committee members present may elect one among them to perform the duties of the Chair.

(f) The Committee will maintain minutes of its meetings which will be filed with the minutes of the Board of Directors. A copy of the Minutes of each meeting of the Committee shall be provided to each member of the Committee, within twenty (20) calendar days from the meeting date. Minutes of Committee meetings will be made available to the Board of Directors upon approval of those minutes by the Committee members.

(g) The Committee, through its Chair, will provide verbal reports outlining issues, actions, and recommendations to the Board at regular Board meetings.

8. SPECIFIC RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties, the Committee shall:

8.1 Financial Reporting

(a) While the Committee has the responsibilities and powers set forth in this Mandate, it shall not be its duty to plan or conduct audits or to determine that the Corporation’s financial statements and disclosures are complete and accurate and in accordance with CGAAP and applicable rules and regulations; these are responsibilities of Management and the external auditors. Management, not the Committee or the external auditors, is responsible for preparing complete and accurate financial statements and disclosures in accordance with CGAAP and other applicable rules and regulations. The Committee needs to understand and assess the financial statements and related information. Accordingly, the Committee must review the Corporation’s interim and annual financial statements and the annual Management Representation Letter with assigned Management and the external auditors (annual statements only) to gain reasonable assurance that the statements, present fairly the Corporation’s financial position and performance, are in accordance with CGAAP and the policies of the OEB, and constitute a fair presentation of the Corporation's financial condition, and report thereon in a timely manner to the Board before such statements are approved by the Board;

(b) receive from the external auditors reports on their audit of the annual financial statements;

(c) receive from Management a copy of the Representation Letter, provided to the external auditors, and receive from Management any additional representations required by the Committee;

(d) review and, if appropriate, recommend approval to the Board prior to publication of all news releases and publications issued by the Corporation with respect to the Corporation's financial statements including, if applicable, the Annual Report and Management Discussion & Analysis; and

(e) if applicable, satisfy itself that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements in order to satisfy itself that such information is fairly presented.

8.2 Financial Management

(a) Review the appropriateness of all of the Corporation's present and proposed accounting policies and all major issues regarding accounting principles and financial statement presentations (including any significant changes in the Corporation's selection or application of accounting principles).

(b) receive from Management, and review, the Corporation's annual business plan, together with the operating and capital budgets, to ensure that they are appropriate for the needs of the Corporation; receive and review quarterly updates on capital spending progress.

(c) review banking arrangements, signing authorities, and cash management controls to ensure that they are appropriate to the needs of the Corporation. Review issues relating to liquidity, capital resources and contingencies that could affect liquidity. Review all plans for treasury operations including financial derivatives and hedging activities. Review all material off-balance-sheet transactions, contingent liabilities and transactions with related parties;

(d) review annually the financial staff succession planning;

(e) receive periodic reports from Management for information on significant changes to current pricing and any related implications on profitability;

(f) consider any other matter relating to the financial management of the Corporation referred to the Committee by the Board; and

(g) review the report prepared by management on all Ontario Energy Board cost of service rate filings.

8.3 Investment Monitoring

(a) Review the Investment Policy at least annually and make necessary amendments;

(b) evaluate and recommend to the Board, the appointment of Investment Managers, if required, taking into account criteria including relevant experience and expertise, structure of the organization, suitability of investment style, turnover of personnel, capacity and servicing capabilities, investment performance record, including consistency of performance and risk, and investment management fees;

(c) monitor investment results on a minimum of a quarterly basis according to the return objectives defined in the Investment Policy;

(d) review, at least annually, the Investment Manager’s performance;

(e) report quarterly on the Corporation’s investment status and holdings to the Board; and

(f) review all investments and transactions that could adversely affect the return on the Corporation’s investments that are brought to the Committee’s attention by, including but not limited to, the external auditor or Management.

8.4 Financial Risk and Uncertainty

The Committee shall gain reasonable assurance that financial risk is being effectively managed and mitigated by:

(a) reviewing with Management the Corporation’s tolerance for financial risk;

(b) identifying and monitoring significant financial risks facing the Corporation;

(c) evaluating and considering the Corporation’s policies and any proposed changes thereto for managing these significant financial risks;

(d) reviewing plans, processes and programs to manage and mitigate such risks;

(e) reviewing policies, and compliance therewith, that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

(f) receiving and review a report from Management and the Corporations Insurance broker consultants on the adequacy of insurance coverage maintained by the Corporation for general liability, employee fidelity, and business interruption;

(g) regularly reporting its findings to the Board; and

(h) reviewing regularly with Management, the external auditors, the internal auditors and the Corporation's legal counsel, any legal claim or other contingency that could have a material effect on the financial position of the Corporation and the manner in which these matters have been disclosed and/or provided for in the financial statements.

8.5 Financial Controls and Control Deviations

(a) Review the processes Management has put in place to maintain appropriate internal controls and monitor compliance with internal control policies;

(b) receive from the internal auditor and external auditors, at least annually, their assessment of the control environment; and

(c) receive regular reports from Management, the internal auditor, the external auditors and the Corporation's legal counsel on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto.

8.6 Internal Control and Information Systems

(a) Review and obtain reasonable assurance that the internal control and information systems are operating effectively to produce materially accurate, appropriate, and timely management and financial information;

(b) obtain reasonable assurance by discussions with and reports from Management, the internal auditor and the external auditors that the information systems, security of information and business recovery plans are adequate and reliable, and that the internal control systems and procedures are properly designed and effectively implemented;

(c) review adequacy of accounting and finance resources, as required; and

(d) undertake any and all required investigations, and other actions, in relation to the suspected material non-compliance with accounting policies, internal controls or use of the services of external and/or internal auditors or other third parties, as deemed appropriate, to ascertain whether any non-compliance has occurred and thereafter, if deemed appropriate, report on such matters to the Board.

8.7 Compliance with Laws and Regulations

(a) Review regular reports (Statutory Declarations) from Management with respect to the Corporation's compliance with laws and regulations having a material impact on the financial statements including: tax and financial reporting laws and regulations; legal withholding requirements; other laws and regulations which expose the members of Board to liability;

(b) confirm with Management that the Corporation is in compliance with laws and regulations having a material impact on the financial statements including: tax and financial reporting laws and regulations; legal withholding requirements; other laws and regulations which expose the members of Board to liability; and

(c) discuss with Corporation's legal counsel any significant legal, compliance or regulatory matters that may have a material effect specifically related to the financial statements of the Corporation or on the compliance policies of the Corporation.

8.8 Relationship with the External Auditors

(a) Recommend to the Board and Shareholder the selection and appointment of the external auditors;

(b) recommend to the Board the remuneration and the terms of engagement of the external auditors;

(c) if necessary, recommend to Board the removal of the current external auditors and replacement with new external auditors;

(d) review the performance of the external auditors at least annually;

(e) receive annually from the external auditors an acknowledgement in writing that their primary responsibility and accountability are to the Committee (Engagement Letter);

(f) receive a report annually from the external auditors with respect to their independence (Independence Letter), such report to include a disclosure of all engagements and fees related thereto for non-audit services provided to the Corporation;

(g) establish a policy with Management which non-audit services do not require pre-approval. Bring to the attention of the Chair of the Committee all requests for all other non-audit services to be performed by the external auditors for the Corporation before such work is commenced and a policy for permitting the Committee Chair to approve such services up to an amount of $10,000 without consulting the Committee.

(h) be satisfied that there is no threat to the external auditors objectivity and independence in the conduct of the audit from providing such services;

(i) review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, the materiality levels which the external auditors propose to employ, areas of audit risk, staffing of the audit, and timetable;

(j) meet at least annually in-camera with the external auditors in the absence of Management to discuss any matters that the Committee believes should be discussed. In addition it should determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examination by the external auditors or the reporting of their findings to the Committee;

(k) be satisfied of the existence of effective communication processes between Management and external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, Management and the Committee;

(l) receive reports on the work of the external auditors and the resolution of disagreements between Management and the external auditors with respect to financial reporting. Obtain explanations from management and where necessary the external auditors, as to why certain issues might remain unadjusted; and

(m) request that the external auditors provide to the Committee, at least annually, a written report describing the external auditors' internal quality assurance policies and procedures as well as any material issues raised in the most recent internal quality assurance reviews, or any inquiry or investigation conducted by government or regulatory authorities (including the Ontario Energy Board).

8.9 Relationship with the Internal Auditor

(a) Establish with the internal auditor the Committee's expectations of the internal audit function;

(b) appoint the internal auditor;

(c) review the performance and reports of the internal auditor on a quarterly basis;

(d) receive annually from the internal auditor an acknowledgement in writing that their primary responsibility and accountability are to the Committee (Engagement Letter);

(e) annually review a report on the internal audit function with respect to the terms of reference, organization, staffing, independence, performance and effectiveness of the internal audit services, receive, approve and monitor the execution of the annual internal audit plan, including the financial risk management measures proposed by the internal auditor, and obtain assurances in respect of conformity with the Canadian Institute of Chartered Accountants (CICA)'s professional standards and with the Institute of Internal Auditors (IIA) and other regulatory bodies' requirements, and recommendations of management and of the internal auditor;

(f) review significant internal audit findings and recommendations and management's response thereto;

(g) to perform integrated financial risk management with the assistance of internal auditor once in every twelve months.

8.10 Other Responsibilities

(a) Investigate any matters that, in the Committee's discretion, fall within the Committee's duties;

(b) review and approve the Corporation's policies with respect to the hiring of partners, employees and former partners and employees of the current and former external auditors;

(c) work with the CEO on any appointment or any dismissal of the CFO or internal auditor and then recommend to the Board the applicable appointment or removal of the CFO or internal auditor and a report to be provided to the Committee;

(d) any changes to the internal audit functions to be intimated to the Committee;

(e) establish procedures for the confidential receipt, retention and treatment of complaints received by the Corporation and/or Board regarding the Corporation's accounting, internal accounting controls or auditing matters; and the confidential anonymous submission, retention and treatment of concerns by employees regarding questionable accounting or auditing matters; and require that all such matters be reported to the Committee together with a description of the resolution of the complaints or concerns and thereafter report these matters to the Board; and

(f) monitor the key financial performance indicators set out in the annual business plan.

9. ACCOUNTABILITY:

9.1 The Committee shall review corporate policies that are within the scope of the roles and responsibilities specified by these terms of reference prior to submission for approval by the Board; monitor compliance on a regular basis; and ensure these policies are periodically reviewed and kept current.

9.2 The Committee shall perform such other duties as may be assigned to it by the Board from time to time or as may be required by applicable law.

9.3 The Committee will annually review its Mandate and Charter, policies and procedures each year at its third quarter meeting to assess its adequacy and endeavour to keep them abreast of "best practices" for a Finance and Audit Committee. Any proposed amendments to the Mandate and Charter, policies or procedures will be submitted to the Board through the Governance and Risk Committee and if agreed to by the Board, will thereafter be put into effect.

OAKVILLE HYDRO CORPORATION

GOVERNANCE AND RISK COMMITTEE

MANDATE AND CHARTER

The Board's Mandate for the Governance and Risk Committee

Adopted: November 18, 2010
Revised: December 6, 2012

1. OBJECTIVE

The Board of Directors (the "**Board**") of **OAKVILLE HYDRO CORPORATION** is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of Oakville Hydro Corporation, and its affiliates (collectively, the "Corporation"). With respect to OAKVILLE HYDRO ELECTRICITY DISTRIBUTION INC. ("OHEDI"), this responsibility is shared with the Board of Directors of OHEDI.

Governance and organizational effectiveness of the Board and strategy and risk management constitute significant aspects of the management of the Board's business and affairs.

To assist the Board in fulfilling its responsibilities, the Board has established a committee of the Board known as the Governance and Risk Committee (the "Committee") to advise the Board with respect to governance, risk and related matters and to make recommendations to the Board relating to these matters.

The Committee shall develop and present to the Board, for its approval, a Charter which includes a description of the activities in which the Committee will engage for the purpose of advising and making recommendations to the Board with respect to governance, risk and related matters.

2. COMPOSITION

The Committee shall be appointed annually by the Board and consist of a minimum of three (3) members and a maximum of five (5) members, with a majority being members of the Board. The Committee Chair and the members of the Committee shall be nominated by the Advisory and Nominating Committee of the Board, and approved by the Board. The Chair shall be a Board member. In addition, the Board Chair and President and CEO shall be ex-officio non-voting members. The Committee may appoint ad-hoc non-voting members to the Committee, as required, to assist the Committee in fulfilling its Mandate.

Governance & Risk Committee Charter

The Committee's Charter outlines how the Committee will satisfy the requirements set forth by the Board in its Mandate. This Charter comprises:

- Operating Principles
- Operating Procedures
- Specific Responsibilities and Duties

3. OPERATING PRINCIPLES

The Committee shall fulfill its responsibilities within the context of the following principles:

3.1 Committee Values

The Committee members will act in accordance with the Board's policies and industry best practices, as applicable.

3.2 Communications

The Chair and members of the Committee expect to have direct, open and frank communications throughout the year with the Board Chair, other Committee Chairs and Management, as applicable.

3.3 Committee Work plan

The Corporate Secretary in consultation with the Committee and Management shall develop an annual Committee work plan responsive to the Committee's responsibilities as set out in this Charter and update it every 12 months.

The Committee will review its annual work plan at its third quarter meeting in each fiscal year.

3.4 Meeting Agenda

The Committee meeting agendas shall be the responsibility of the Committee Chair. The Corporate Secretary will develop meeting agendas in consultation with the Committee Chair, Committee members, the Board Chair and assigned Management.

3.5 Committee Expectations and information needs

The Committee shall communicate its expectations to Management with respect to the nature, timing and extent of its information needs. The Committee expects that written material supporting agenda items will be received from Management at least seven days in advance of the meeting dates.

3.6 In-Camera Meetings

At each meeting of the Committee, the members of the Committee shall meet at their, discretion in private sessions that allow the Committee to discuss matters (a) amongst themselves, and (b) with management. Actionable items resulting from these sessions will be recorded in the minutes in accordance with Guidelines for *in camera* meetings.

3.7 Adequate Resources

The Committee should have adequate resources to discharge its duties as mentioned in this mandate subject to prior budget provision. Members of the Committee shall be entitled to receive such remuneration for acting as members of the Committee as the Board may determine from time to time consistent with its remuneration policies for all Board and Committee members.

3.8 In all instances where the Committee believes that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of external experts, the Chair shall engage the necessary experts subject to prior notice and approval of the Board. The Board shall be kept apprised of both the selection of the experts and the experts findings through the Committee's regular verbal reports by its Chair at regular Board meetings.

4. <u>OPERATING PROCEDURES</u>

4.1 Committee Self-Assessment

The Committee shall annually review, discuss and assess its own performance and individual members' performance. In addition, the Committee shall annually review its role and responsibilities. The Committee shall reconsider its Mandate and Charter at least annually and report to the Board with any recommendations for change.

4.2 Frequency and calling of Committee meetings

The Committee shall meet every quarter or more frequently as circumstances dictate. Meetings shall be held at the call of the Chair of the Committee or upon the request to the Chair of the Committee by two members of the Committee or the Management.

4.3 Quorum

A quorum shall be a majority of the voting members of the Committee. Each voting member will be entitled to one vote and the Committee Chair will not have a second or casting vote in the case of an equality of votes. No proxies shall be permitted.

4.4 Secretary of Committee meetings

Unless the Committee otherwise specifies, the Corporate Secretary shall act as Secretary of all meetings of the Committee. In the absence of the Secretary, the Chair of the Committee shall designate a person to act as the Secretary of the meeting.

4.5 hair of Committee meetings

In the absence of the Chair of the Committee at any meeting of the Committee, the Chair of the Committee may delegate a Committee member to perform the duties of the Chair or the Committee members present may elect one among them to perform the duties of the Chair.

4.6 Minutes of Committee meetings

The Committee will maintain minutes of its meetings which will be filed with the minutes of the Board of Directors. A copy of the Minutes of each meeting of the Committee shall be provided to each member of the Committee within 20 calendar days from the meeting date. Minutes of Committee meetings will be made available to the Board of Directors upon approval of those minutes by the Committee members.

5. SPECIFIC RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties to advise the Board with respect to governance, and related matters of organizational effectiveness and strategic planning and risk management and to make recommendations to the Board relating to these matters, the Committee shall in consultation with the President and CEO:

5.1 Governance structure

Make recommendations to the Board respecting the governance structure of the Board and the Corporation.

5.2 Board and Committee policies

Oversee the development of and any amendments to the Board and Committee policies.

5.3 Position Descriptions

Oversee the development and any amendments of position descriptions for the Officers of the Board.

5.4 Corporate and Regulatory Compliance Best Practices

Review and monitor industry best practices regarding all corporate and regulatory governance standards and practices applicable to the Corporation and make recommendations as appropriate from time to time.

5.5 Disclosure

Review and approve the disclosure with respect to corporate governance practices required to be included in any regulatory filings of the Corporation or before any public disclosure thereof by the Corporation.

5.6 Self Assessment

Develop and make recommendations to the Board on, and oversee the process for annual assessment and evaluation of the performance of the Board, the Board Chair, the Board members and the Board's Committees.

5.7 Orientation

Review, monitor and make recommendations regarding the orientation and ongoing development of existing and new Directors, Officers and Committee members.

5.8 Review of Corporate Documents

Annually review (i) the Board Reference Manual outlining the policies and procedures by which the Board will operate (ii) the Corporation's by-laws, articles, and (iii) any changes in applicable corporate laws to ensure their continued adequacy and relevance. Oversee the development of, and any amendments to, the Mandate and Charter of the Board and of all Committees of the Board, and the Chair role description of the Board Chair and Committee Chairs.

5.9 Meetings

Assess the needs of the Board in terms of the frequency and location of Board, Committee, and Members meetings, meeting agendas, discussion papers, reports and information, and the conduct of the meetings and make recommendations to the Board as required.

5.10 Strategic Planning

Provide input during the strategic planning process within the Corporation and review, recommend to the Board for approval and monitor the strategic plan including fundamental financial and business strategies and objectives.

5.11 Risk Management

(1) Review regular reports from Management assessing the major strategic, reputational, and operational risks facing the Corporation.

(2) Review management's risk management framework/process regarding risk identification, management, monitoring, and reporting of risks. (Note - Financial

risks will be handled by the Finance and Audit Committee and that Committee will regularly report its findings to the Board.)

(3) Review management's risk management framework/process regarding risk identification, management, monitoring, and reporting of risks.

5.12 Key Performance Indicators

(1) Receive and regularly review summary reports of specified performance indicators; monitor progress on strategic initiatives; monitor compliance with Code of Conduct, identify problem areas where further investigation may be warranted.

(2) Establish for Board approval, appropriate performance indicators relating to strategic, risk, and organizational performance.

5.13 Communication Process

Ensure an effective process is established and applied for the communication of strategic and risk management initiatives among the Board, the organization, and external stakeholders.

5.14 Advise Board

Advise the Board on matters of non-financial policy, public affairs, inter-corporation affairs and inter-local distribution company affairs.

5.15 Other Matters

Consider any other matter relating to the governance and organizational effectiveness of the Board referred to the Committee by the Board.

6. ACCOUNTABILITY

The Committee will report on its deliberations to the Board through verbal reports by its Chair at regular Board meetings.

The Committee will review its Mandate and Charter each year at its third quarter meeting to assess adequacy and endeavour to keep Committee members abreast of "best practices" for a Governance and Risk Committee. Any proposed amendments to the Mandate and Charter will be submitted by the Committee to the Board and if agreed to by the Board, will thereafter be put into effect.

OAKVILLE HYDRO CORPORATION

HUMAN RESOURCES COMMITTEE

MANDATE AND CHARTER

<u>The Board's Mandate for the Human Resources Committee</u>

Adopted: November 18, 2010
Revised: December 6, 2012

1. OBJECTIVE

The Board of Directors ("Board") of Oakville Hydro Corporation is responsible for overseeing and monitoring all significant aspects of the management of the business and affairs of Oakville Hydro Corporation and its affiliates (collectively, the "Corporation"). With respect to Oakville Hydro Electricity Distribution Inc. ("OHEDI"), this responsibility is shared with the Board of Directors of OHEDI.

Human Resources are critical to the success of the Corporation.

To assist the Board in fulfilling its responsibilities, the Board has established a Committee of the Board known as the Human Resources Committee (the "Committee") to advise the Board with respect to

(a) succession planning, performance management plan, compensation and benefit programs for the executive officers and management of the Corporation;

(b) compensation and benefit programs for all other employees of the Corporation;

(c) human resources strategic plan;

(d) organizational development plan;

(e) human resources policies, and

The Committee shall develop and present to the Board, for its approval, a Charter which includes a description of the activities in which the Committee will engage for the purpose of advising and making recommendations to the Board with respect to clause (a) to (e) mentioned above.

2. COMPOSITION OF THE HRC

. The Committee shall be appointed annually by the Board and consist of a minimum of three (3) and a maximum of five (5) members, with a majority being members of the Board. The Committee Chair and the members of the Committee shall be nominated by the Advisory and Nominating Committee of the Board, and approved by the Board. The Chair shall be a Board member. In addition, the Board Chair and President and CEO shall be ex-officio non-voting members. The Committee may appoint ad-hoc non-voting members to the Committee, as required, to assist the Committee in fulfilling its mandate.

HRC Charter

The Committee's Charter outlines how the Committee will satisfy the requirements set forth by the Board in its Mandate. This Charter comprises:

- Operating Principles
- Operating Procedures
- Specific Responsibilities and Duties

3. OPERATING PRINCIPLES

The Committee shall fulfill its responsibilities within the context of the following principles:

3.1 Committee Values

The Committee members will act in accordance with Board policies and industry best practices, as applicable.

3.2 Communications

The Chair and members of the Committee expect to have direct, open and frank communications throughout the year with the Board Chair, other Committee Chairs and Management, as applicable.

The Board Chair shall communicate on behalf of the Committee and the Board directly with the President and CEO with respect to the President and CEO's performance, compensation, development and succession.

3.3 Committee Work Plan

The Corporate Secretary in consultation with the Committee and Management shall develop an annual Committee Work Plan responsive to the Committee's responsibilities as set out in this Charter and update it every 12 months.

The Committee will review its annual work plan at its third quarter meeting in each fiscal year.

3.4 Meeting Agenda

The Committee meeting agendas shall be the responsibility of the Committee Chair. The Corporate Secretary will develop meeting agendas in consultation with the Committee Chair, Committee members, the Board Chair and Management.

3.5 Committee Expectations and Information Needs

The Committee shall communicate its expectations to Management with respect to the nature, timing and extent of its information needs. The Committee expects that written material supporting agenda items will be received from Management at least seven days in advance of the meeting dates.

3.6 In Camera Meetings

At each meeting of the Committee, the members of the Committee shall meet at their discretion in private sessions that allow the Committee to discuss matters (a) amongst themselves, and (b) with management. Actionable items resulting from these sessions will be recorded in the minutes in accordance with Guidelines for *in camera* meetings.

3.7 Adequate Resources

The Committee should have adequate resources to discharge its duties as mentioned in this mandate subject to prior budget provision. Members of the Committee shall be entitled to receive such remuneration for acting as members of the Committee as the Board may determine from time to time consistent with its remuneration policies for all Board and Committee members. In all instances where the Committee believes that in order to properly discharge their fiduciary obligations to the Corporation it is necessary to obtain the advice of external experts, the Chair shall engage the necessary experts subject to prior notice and approval of the Board. The Board shall be kept apprised of both the selection of the experts and the experts findings through the Committee's regular verbal reports by its Chair at regular Board meetings.

4. OPERATING PROCEDURES

The Committee shall fulfill its responsibilities within the context of the following procedures:

4.1 Committee Self-assessment

The Committee shall annually review, discuss and assess its own performance and individual member's performance. In addition, the Committee shall annually review its role and responsibilities.

4.2 Frequency and Calling of Committee Meetings

The Committee shall meet every quarter or more frequently as circumstances dictate. Meetings shall be held at the call of the Chair of the Committee or upon the request of two members of the Committee or management.

4.3 Quorum

A quorum shall be a majority of the voting members of the Committee. Each voting member will be entitled to one vote and the Committee Chair will not have a second or casting vote in the case of an equality of votes. No proxies shall be permitted.

4.4 Secretary of Committee Meetings

Unless the Committee otherwise specifies, the Corporate Secretary shall act as secretary of all meetings of the Committee. In the absence of the Secretary, the Chair of the Committee shall designate a person to act as the Secretary of the meeting.

4.5 Chair of Committee Meetings

In the absence of the Chair of the Committee at any meeting of the Committee, the Chair of the Committee may delegate a Committee member to perform the duties of the Chair or the Committee members present may elect one among them to perform the duties of the Chair.

4.6 Minutes of Committee Meetings

The Committee will maintain minutes of its meetings which will be filed with the minutes of the Board of Directors. A copy of the Minutes of each meeting of the Committee shall be provided to each member of the Committee within twenty (20) calendar days from the meeting date. Minutes of Committee meetings will be made available to the Board of Directors upon approval of those minutes by the Committee.

5. ROLES & RESPONSIBILITIES

5.1 Specific Responsibilities and Duties

The Committee will advise and make recommendations to the Board relating to the following matters, in consultation with the President and CEO:

(a) consider and review the human resources strategic plan and monitor its implementation at least annually;

(b) consider and review the organizational development plan;

(c) consider and review the succession plans for the executive management of the Corporation, namely the President and CEO and all Vice Presidents;

(d) consider and approve the SMART Objectives and the total compensation including the specific salary increases of the Vice Presidents;

(e) consider and recommend the SMART Objectives and the total compensation including the specific salary increases of the President and CEO to the Board for approval;

(f) consider and approve the performance evaluation for the Vice Presidents of the corporation including President and CEO;

(g) consider and approve the recommendation to the Board on the total compensation program and benefit program for the executive management of the Corporation;

(h) review with the President and CEO the total compensation program for the executive management of the Corporation before any decision or approval is made concerning such or any recommendation is made to the Board on changes to the total compensation program;

(i) report to the Board on the factors considered by the Committee in approving the total compensation program for the executive management of the Corporation;

(j) consider, review and approve any new, significant or special employment contracts or arrangements for senior management of the Corporation that may be different in principle from those already in place and used by the Corporation;

(k) review and approve the recommendation to the Board on the Corporation's compensation and benefit plans;

(l) review and approve the Corporation's Human Resources Policies, including the Employee Code of Conduct;

(m) provide input to the Board Chair in conducting the annual performance review of the President and CEO by the Board Chair and the Committee Chair; and

(n) perform such other duties as may from time to time be assigned to it by the Board and accepted by the Committee as appropriate duties for it to undertake.

The Committee shall have the right, for the purposes of discharging the powers and responsibilities as defined in its Charter, Mandate and Work Plan, to inspect any relevant records of the Corporation with the exception of any documentation held by the Corporation containing private and confidential information with respect to the senior management of the Corporation or any other employee.

5.2 Maintaining Integrity

The Committee shall ensure that senior management review its systems and documentation, and monitors the controls and procedures within the Corporation in order to maintain its integrity including its internal controls and procedures for human resources reporting and compliance with privacy legislation and all relevant employment related legislation.

5.3 Key Performance Indicators

The Committee shall receive and regularly review reports of specified performance indicators.

5.4 Communication Process

The Committee shall ensure an effective process is established and applied for the communication of the executive compensation and Human Resources programs between the Board and the Corporation.

5.5 Other Business

The Committee shall consider any other relevant matters relating to the discharge of its Mandate and Charter or referred to it by the Board.

6. ACCOUNTABILITY:

6.1 The Committee will report on its deliberations to the Board through verbal reports by its Chair at regular Board meetings.

6.2 The Committee will review its Mandate and Charter each year at its third quarter meeting to assess its adequacy and endeavour to keep Committee members abreast of “best practices” for a Human Resources Committee. Any proposed amendments to the Mandate and Charter will be submitted to the Board through the Governance and Risk Committee and if agreed to by the Board, will thereafter be put into effect.

Overview:

Rate Base Overview

The rate base for the purposes of calculating the revenue requirement used in this Application follows *Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications* issued on July 17th, 2013. In accordance with the Filing Requirements, Oakville Hydro has calculated the rate base based on the average of the 2014 Test Year opening and closing balances of gross fixed assets and accumulated depreciation, plus a working capital allowance calculated as 13% of the sum of the cost of power and controllable expenses.

The net fixed assets include those distribution assets that are associated with activities that enable the distribution of electricity. The 2014 rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing, collections and administration expenses.

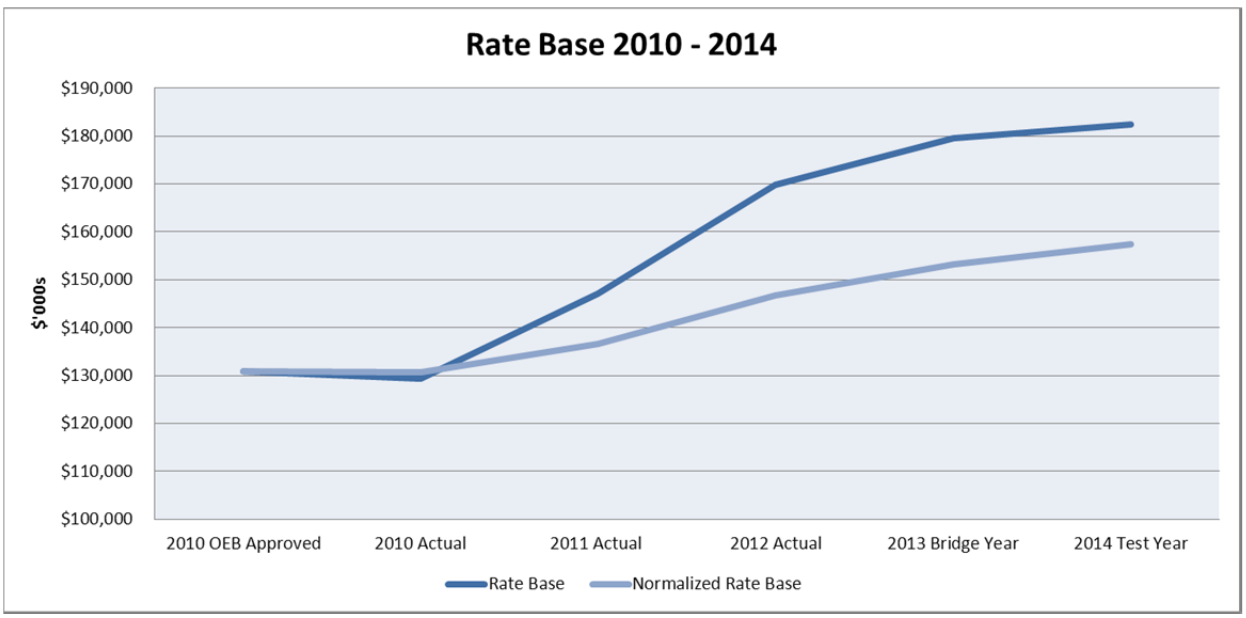
Oakville Hydro has provided its rate base calculations for the years, 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, 2013 Bridge Year and 2014 Test Year in Table 2-1. The 2013 Bridge Year capital costs include seven months of actual costs and five months of forecasted costs. Oakville Hydro has calculated its 2014 rate base as $182,335,331, to be used to determine the proposed revenue requirement.

This represents an increase of $51,463,588 over the 2010 Board Approved year. As shown in Table 2-1, Drivers of Rate Base Increases, this increase is as a result of normal annual capital additions, ongoing depreciation, two major initiatives: the Smart Meter implementation and the design and construction of the Glenorchy Municipal Transformer Station, and the increase in Working Capital.

Table 2-1, Drivers of Rate Base Increases

Cost Drivers		Increase in Rate Base
2010 Board Approved	$	130,871,743
Normal Capital Additions (net of Ongoing Depreciation and Stranded Meters)		19,681,121
Net Book Value of Smart Meters		6,529,840
Net Book Value of Glenorchy MTS		21,728,516
Increase in Working Capital		3,524,111
2014 Test Year	$	182,335,331

The following graph illustrates the difference between the total rate base and the normalized rate base, excluding the Smart Meter initiative and the Glenorchy Municipal Transformer Station.



As shown in Table 2-2, the forecasted average net fixed assets for the proposed 2014 Test Year is $159,059,604. This represents an increase versus the 2013 Bridge Year of $5,672,102 or 3.7%. The significant increase in average net fixed assets of $47,939,477 or 43.1% over the 2010 Board Approved year, shown in Table 2-3, is due in part to the Smart Meter costs and the construction of the Glenorchy Municipal Transformer Station which are described below.

Table 2-2 - Summary of Rate Base

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Opening Balance Gross Fixed Assets	$ 187,960,573	$ 184,824,364	$ 195,344,591	$ 231,660,581	$ 257,748,723	$ 269,443,469
Closing Balance Gross Fixed Assets	202,681,800	195,344,591	231,660,581	257,748,723	269,443,469	286,050,896
Average Gross Fixed Assets	**195,321,187**	**190,084,477**	**213,502,586**	**244,704,652**	**263,596,096**	**277,747,183**
Opening Balance Accumulated Depreciation	79,297,219	78,668,456	85,365,493	92,913,946	106,035,180	114,382,008
Closing Balance Accumulated Depreciation	89,104,901	85,365,493	92,913,946	106,035,180	114,382,008	122,993,150
Average Accumulated Depreciation	**84,201,060**	**82,016,974**	**89,139,719**	**99,474,563**	**110,208,594**	**118,687,579**
Average Net Fixed Assets	**111,120,127**	**108,067,503**	**124,362,866**	**145,230,089**	**153,387,502**	**159,059,604**
Working Capital	131,677,443	141,586,399	151,444,308	163,311,261	178,637,985	179,044,057
Working Capital Allowance	19,751,616	21,237,960	22,716,646	24,496,689	26,795,698	23,275,727
Rate Base	**$ 130,871,743**	**$ 129,305,463**	**$ 147,079,513**	**$ 169,726,778**	**$ 180,183,200**	**$ 182,335,331**

Table 2-3 – Summary of Average Net Fixed Assets for Rate Base – including Smart Meters and the Glenorchy Municipal Transformer Station

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Average Gross Fixed Assets	$ 195,321,187	$ 190,084,477	$ 213,502,586	$ 244,704,652	$ 263,596,096	$ 277,747,183
Average Accumulated Depreciation	84,201,060	82,016,974	89,139,719	99,474,563	110,208,594	118,687,579
Average Net Fixed Assets	**$ 111,120,127**	**$ 108,067,503**	**$ 124,362,866**	**$ 145,230,089**	**$ 153,387,502**	**$ 159,059,604**
Cumulative Change		- 3,052,624	13,242,740	34,109,962	42,267,376	47,939,477
Cumulative Change %		-2.7%	11.9%	30.7%	38.0%	43.1%

Smart Meter Initiative

Oakville Hydro incurred cumulative capital costs of $10,173,225 for the installation of smart meters and the implementation of Time-Of-Use ("TOU") billing for residential and General Service < 50 kW customers. Smart meters were part of a public policy directive, but will facilitate improved customer service as the functionality associated with the available smart meter data evolves and improves. The recovery of capital costs associated with smart meters was the subject of a Smart Meter Prudence Review application (EB-2012-0193). The outcome of that application was a Board decision that approved a smart meter incremental revenue rate rider which will expire on April 30, 2014.

Glenorchy Municipal Transformer Station ("Glenorchy MTS")

In 2011, Oakville Hydro completed the construction of the Glenorchy Municipal Transformer Station in order to service the customers of north Oakville with a capital cost of $22,860,578. This station was the subject of an Incremental Capital Module ("ICM") application as part of EB-2010-0104 and was approved by the Board. As a result of the Board's approval, an ICM rate rider was established which will expire on April 30, 2014. This project is discussed in more detail in Tab 2, Schedule 3 (Gross Assets Summary) of this Exhibit.

Before the impact of the capital costs associated with the Smart Meter implementation and the design and construction of the Glenorchy Municipal Transformer Station are reflected in rate base, the average net fixed assets are forecasted to be $134,134,726. As displayed in Table 2-4 below, this represents an increase of 20.7% over the 2010 Board Approved year, resulting in an average annual increase over the four year period from 2010 to 2014 of 5.2%.

Table 2-4 – Summary of Average Net Fixed Assets for Rate Base – excluding Smart Meters and the Glenorchy Municipal Transformer Station

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Average Gross Fixed Assets	$ 195,321,187	$ 192,390,452	$ 206,126,853	$ 224,086,152	$ 237,080,004	$ 251,200,533
Average Accumulated Depreciation	84,201,060	82,950,324	92,222,215	101,897,958	110,055,754	117,065,807
Average Net Fixed Assets	**$ 111,120,127**	**$ 109,440,128**	**$ 113,904,639**	**$ 122,188,194**	**$ 127,024,250**	**$ 134,134,726**
Cumulative Change		- 1,679,999	2,784,512	11,068,067	15,904,123	23,014,600
Cumulative Change %		-1.5%	2.5%	10.0%	14.3%	20.7%

Variance Analysis of Rate Base

2010 Board Approved vs. 2010 Actual

As outlined in Table 2-5, the 2010 Actual Rate Base was $1,566,280 lower than that approved by the Board. This is primarily due to a decrease in average Net Book Value of $3,052,624, partly offset by an increase in the working capital allowance.

Table 2-5 - 2010 Board Approved Rate Base vs. 2010 Actual Rate Base

Description	2010 OEB Approved	2010 Actual	Variance from 2010 OEB Approved
Reporting Basis	CGAAP	CGAAP	CGAAP
NET BOOK VALUE			
Gross Fixed Assets - Closing	$ 202,681,800	$ 195,344,591	-$ 7,337,209
Accumulated Depreciation - Closing	89,104,901	85,365,493	- 3,739,408
Net Book Value - Closing	113,576,899	109,979,098	- 3,597,801
Average Net Book Value	**111,120,127**	**108,067,503**	**- 3,052,624**
WORKING CAPITAL - 15% ALLOWANCE APPROACH			
Cost of Power	17,975,706	19,557,632	1,581,926
OM&A	1,775,910	1,680,328	- 95,583
15% Working Capital	**19,751,616**	**21,237,960**	**1,486,343**
Total Rate Base	**$ 130,871,743**	**$ 129,305,463**	**-$ 1,566,280**

The decrease in average Net Book Value of $3,052,624 was driven primarily by the removal of the stranded mechanical meters in the 2010 Actuals. The stranded mechanical meters were included in rate base in Oakville Hydro's 2010 Cost of Service application. In 2010, Oakville Hydro transferred the cost of its stranded meters out of rate base, from Account 1860 – Meters to Account 1555 - Sub-Account Stranded Meter Costs, in accordance with the *Board's Guideline G-2008-0002, Smart Meter Funding and Cost Recovery*. The resultant Actual Average Net Book Value was less than the 2010 application by $1,397,625. The treatment of stranded meters is discussed in more detail in Exhibit 2, Tab 4.

The impact of this transfer was partly offset by an increase in capital additions for 2010. In the 2010 Cost of Service application, Oakville Hydro projected capital additions of $14,721,227 for 2010. In 2010, Oakville Hydro capitalized $16,615,311, or $1,894,084 more than planned. The increased capital additions were primarily due to unanticipated increased spending on transformer replacements and voltage conversion (Woodhaven Park), replacing the rear lot distribution system, road-widening projects and underground rebuilds (Poletrans replacements). These projects are discussed in detail in Tab 5, Schedule 2 of this Exhibit – Capital Additions.

The working capital allowance increased from the 2010 Board Approved amount as a result of an increase in the Cost of Power.

2010 Actual vs. 2011 Actual

As outlined in Table 2-6, the 2011 Actual Rate Base was $17,774,050 higher than 2010, driven by an increase in average Net Book Value of $16,295,364 and working capital allowance of $1,478,686.

Table 2-6 - 2010 Actual Rate Base vs. 2011 Actual Rate Base

Description	2010 Actual	2011 Actual	Variance from 2010 Actual
Reporting Basis	CGAAP	CGAAP	CGAAP
NET BOOK VALUE			
Gross Fixed Assets - Closing	$ 195,344,591	$ 231,660,581	$ 36,315,990
Accumulated Depreciation - Closing	85,365,493	92,913,946	7,548,454
Net Book Value - Closing	109,979,098	138,746,635	28,767,537
Average Net Book Value	**108,067,503**	**124,362,866**	**16,295,364**
WORKING CAPITAL - 15% ALLOWANCE APPROACH			
Cost of Power	19,557,632	20,719,415	1,161,783
OM&A	1,680,328	1,997,231	316,903
15% Working Capital	**21,237,960**	**22,716,646**	**1,478,686**
Total Rate Base	**$ 129,305,463**	**$ 147,079,513**	**$ 17,774,050**

The 2011 Net Book Value increased by $28,767,537 due to an increase in net capital additions of $36,315,990. The net book value in 2011 was partially offset by depreciation of $7,548,454. The increase in additions was driven by the addition of the Glenorchy Municipal Transformer Station for $22,860,578. In September 2010, Oakville Hydro filed an ICM application (EB-2010-0104) for the recovery of the capital costs of $22,860,578 associated with the design and construction of the Glenorchy Municipal Transformer Station. This application was approved as well as an associated rate rider. Further details on this project are in Tab 5, Schedule 6 of this Exhibit.

The increase in Rate Base from 2010 to 2011 is also partly due to an increase in working capital expenses driven by the Cost of Power. The 2011 actual Cost of Power was $7,745,221 higher than the 2010 amount, translating into an increase in rate base (at 15%) of $1,161,783.

2011 Actual vs. 2012 Actual

As outlined in Table 2-7, the 2012 Actual Rate Base was $22,647,265 higher than 2011, driven by an increase in average Net Book Value of $20,867,222 and working capital allowance of $1,780,043, primarily due to an increase in the Cost of Power.

Table 2-7 - 2011 Actual Rate Base vs. 2012 Actual Rate Base

Description	2011 Actual	2012 Actual	Variance from 2011 Actual
Reporting Basis	CGAAP	CGAAP	CGAAP
NET BOOK VALUE			
Gross Fixed Assets - Closing	$ 231,660,581	$ 257,748,723	$ 26,088,142
Accumulated Depreciation - Closing	92,913,946	106,035,180	13,121,233
Net Book Value - Closing	138,746,635	151,713,543	12,966,908
Average Net Book Value	**124,362,866**	**145,230,089**	**20,867,222**
WORKING CAPITAL - 15% ALLOWANCE APPROACH			
Cost of Power	20,719,415	22,370,012	1,650,597
OM&A	1,997,231	2,126,677	129,446
15% Working Capital	**22,716,646**	**24,496,689**	**1,780,043**
Total Rate Base	**$ 147,079,513**	**$ 169,726,778**	**$ 22,647,265**

This increase in average Net Book Value was due to the capitalization of the capital costs of $10,131,152 associated with the Smart Meter initiative in 2012 as approved in Oakville Hydro's Smart Meter prudence review (EB-2012-0193) and the full year impact of the capitalization of the Glenorchy Municipal Transformer Station.

The increase in Rate Base from 2011 to 2012 is also partly due to an increase in working capital expenses driven by the Cost of Power. The 2012 actual Cost of Power was $11,003,977 higher than the 2011 amount, translating into an increase in rate base (at 15%) of $1,650,597.

2013 Actual vs. 2012 Actual

As outlined in Table 2-8, the 2013 Bridge Year (Old CGAAP) Rate Base is projected to be $9,898,243 higher than 2012, driven by an increase in average Net Book Value of $8,043,554 and an increase in working capital allowance of $1,854,689.

Table 2-8 - 2012 Actual Rate Base vs. 2013 Bridge Year (Old CGAAP)

Description	**2012 Actual**	**2013 Bridge Year old CGAAP**	**Variance from 2012 Actual**
Reporting Basis	CGAAP	CGAAP	CGAAP
NET BOOK VALUE			
Gross Fixed Assets - Closing	$ 257,748,723	$ 272,757,460	$ 15,008,738
Accumulated Depreciation - Closing	106,035,180	117,923,717	11,888,537
Net Book Value - Closing	151,713,543	154,833,743	3,120,201
Average Net Book Value	**145,230,089**	**153,273,643**	**8,043,554**
WORKING CAPITAL - % ALLOWANCE APPROACH			
Cost of Power	22,370,012	24,077,157	1,707,145
OM&A	2,126,677	2,274,221	147,543
15% Working Capital	**24,496,689**	**26,351,378**	**1,854,689**
Total Rate Base	**$ 169,726,778**	**$ 179,625,021**	**$ 9,898,243**

Net Capital Assets in 2013 are projected to increase by $3,120,201 driven by capital additions of $15,008,738. The average net book value in 2013 includes the full year impact of smart meters on the average balance.

The increase in Rate Base from 2012 to 2013 is also due to an increase in the working capital allowance driven primarily by an increase in the cost of power.

2013 Bridge Year Old CGAAP vs. 2013 Bridge Year New CGAAP

Oakville Hydro will defer the transition to International Financial Reporting Standards (“ IFRS”) until 2015 and prepare financial statements under CGAAP. However, in accordance with the Board’s guidelines published July 17, 2012, Oakville Hydro will implement changes to its depreciation rates and capitalization policy effective January 1, 2013. Table 2-9 highlights the differences that result from these changes. Oakville Hydro’s transition to IFRS and accounting changes under CGAAP are discussed in detail in Exhibit 2, Tab 6.

Table 2-9 - 2013 Bridge Year Rate Base Old CGAAP vs. New CGAAP

Description	2013 Bridge Year Old CGAAP	2013 Bridge Year New CGAAP	Variance from 2013 Old CGAAP vs New CGAAP
Reporting Basis	CGAAP	CGAAP	
NET BOOK VALUE			
Gross Fixed Assets - Closing	$ 272,757,460	$ 269,443,469	-$ 3,313,991
Accumulated Depreciation - Closing	117,923,717	114,382,008	- 3,541,709
Net Book Value - Closing	154,833,743	155,061,461	227,718
Average Net Book Value	**153,273,643**	**153,387,502**	**113,859**
WORKING CAPITAL - 15% ALLOWANCE APPROACH			
Cost of Power	24,077,157	24,077,157	-
OM&A	2,274,221	2,718,541	444,320
15% Working Capital	**26,351,378**	**26,795,698**	**444,320**
Total Rate Base	**$ 179,625,021**	**$ 180,183,200**	**$ 558,179**

The 2013 Bridge Year (New CGAAP) Rate Base is projected to be $558,179 higher than the 2013 Bridge Year (Old CGAAP) Rate Base, driven by an increase in average Net Book Value of $113,859 and an increase in working capital allowance of $444,320.

Average Net Book Value for 2013 New CGAAP is projected to be $113,859 higher than 2013 Old CGAAP. This increase represents the impact of Oakville Hydro's change to its depreciation rates partially offset by the change to its capitalization policy. Net Book Value is projected to increase by $3,541,709 due to the impact of extending useful lives on distribution assets. This is offset by a decrease of $3,313,991 as costs previously capitalized under Old CGAAP are excluded from capital under New CGAAP. The net increase in Net Book Value from Old CGAAP to New CGAAP of $227,718 is before the adjustment of burdens remaining in 2013 Work-in-Progress of ($99,814). The average impact of this change is an increase of $113,859.

The working capital allowance at 15% has increased by $444,320 under New CGAAP as a result of increased operating expenses of $2,962,133, stemming from the expensing of 2013 burdens previously capitalized under old CGAAP. The burdens associated with 2012 WIP added in 2013 have not been transferred to expense in 2013, as these were incurred in 2012. A detailed reconciliation is provided in Table 2-10.

Table 2-10 – 2013 Bridge Year Impact of Accounting Changes to Rate Base, NBV and Expenses

Description	**2013 Bridge Year Old CGAAP**	**2013 Bridge Year New CGAAP**	**Variance from 2013 Old CGAAP vs New CGAAP**	**Comments**
Gross Fixed Assets - Excluding WIP Additions	$271,380,526	$268,418,392	($2,962,133)	Ineligible overheads incurred in 2013
2013 Additions from 2012 WIP	1,376,935	1,025,077	(351,857)	Ineligible overheads incurred in 2012; cannot be moved to 2013 expense but are included in 1576
Total Gross Fixed Assets - Rate Base	**272,757,460**	**269,443,469**	**(3,313,991)**	
Accumulated Depreciation	117,923,717	114,382,008	(3,541,709)	Change to depreciation rates
Net Book Value - Rate Base	**154,833,743**	**155,061,461**	**227,718**	
WIP	415,121	315,307	(99,814)	Ineligible overheads in 2013 WIP, incurred in 2012; not part of rate base but part of Total PP&E
Net Book Value - Total PP&E	**155,248,864**	**155,376,768**	**127,904**	Amount to be included in 1576
Rate of Return			7,637	Return on Rate Base associated with Account 1576 balance at Weighted Average Cost of Capital
Amount included in Deferral and Variance Rate Rider			**$135,541**	
Cost of Power and OM&A (A)	$175,675,852	$178,637,985	$2,962,133	Overheads expensed based on new capitalization polices
15% Working Capital (A * 15%)	$26,351,378	$26,795,698	$444,320	Impact to Working Capital at 15%

2013 Bridge Year vs. 2014 Test Year

As outlined in Table 2-11, the 2014 Test Year (New CGAAP) Rate Base is projected to be $2,152,131 higher than 2013, driven by an increase in average Net Book Value of $5,672,102 and an decrease in working capital allowance of $3,519,970.

Table 2-11 - 2013 Bridge Year vs. 2014 Test Year

Description	2013 Bridge Year New CGAAP	2014 Test Year New CGAAP	Variance from 2013 Bridge
Reporting Basis	CGAAP	CGAAP	CGAAP
NET BOOK VALUE			
Gross Fixed Assets - Closing	$ 269,443,469	$ 286,050,896	$ 16,607,427
Accumulated Depreciation - Closing	114,382,008	122,993,150	8,611,141
Net Book Value - Closing	155,061,461	163,057,746	7,996,285
Average Net Book Value	**153,387,502**	**159,059,604**	**5,672,102**
WORKING CAPITAL - % ALLOWANCE APPROACH			
Cost of Power	24,077,157	20,751,363	- 3,325,794
OM&A	2,718,541	2,524,364	- 194,177
15%/13% Working Capital	**26,795,698**	**23,275,727**	**- 3,519,970**
Total Rate Base	**$ 180,183,200**	**$ 182,335,331**	**$ 2,152,131**

The 2014 Net Book Value is projected to increase by $7,996,285 from 2013, driven by capital additions including the purchase of an on-site emergency backup transformer for the Glenorchy Municipal Transformer Station in 2014. This project is discussed in further detail in the Appendix A, Distribution System Plan.

The increase in Average Net Book Value from 2013 to 2014 is partly offset by a decrease in working capital allowance of $3,519,970. The decrease is primarily as a result of the reduction in the working capital allowance from 15% to 13% as per the Filing Requirements.

Fixed Asset Continuity Schedules Including Work in Progress

Oakville Hydro has provided Fixed Asset Continuity Schedules including Work-in-Progress ("WIP") for each of 2010 Actuals, 2011 Actuals, 2012 Actuals, 2013 Bridge Year - Old CGAAP, 2013 Bridge Year - New CGAAP and 2014 Test Year as Tables 2-13 through 2-18 in this Exhibit.

The total gross asset balances in Oakville Hydro's Fixed Asset Continuity Statements do not balance to the opening and closing balances of gross assets used to calculate the fixed asset component of rate base. Work-in-Progress has been removed from the fixed asset continuity schedule balances for rate base calculation purposes, as mandated by the Board. A reconciliation is provided in Table 2-12 below.

The opening and closing balances of accumulated depreciation used to calculate the fixed asset component of rate base correspond to the fixed asset continuity schedule. As such there is no reconciliation required for accumulated depreciation.

Table 2-12 – Reconciliation of Opening and Closing Balances

Description	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge New CGAAP	2014 Test
TOTAL GROSS ASSETS FOR RATE BASE	**$ 202,681,800**	**$ 195,344,591**	**$ 231,660,581**	**$ 257,748,723**	**$ 269,443,469**	**$ 286,050,896**
Work In Progress	7,285,640	15,237,370	2,694,853	1,792,056	315,307	-
TOTAL GROSS ASSETS INCLUDING WIP	**$ 209,967,440**	**$ 210,581,961**	**$ 234,355,434**	**$ 259,540,778**	**$ 269,758,777**	**$ 286,050,896**
TOTAL ACCUM DEPRECIATION FOR RATE BASE	**$ 89,104,901**	**$ 85,365,493**	**$ 92,913,946**	**$ 106,035,180**	**$ 114,382,008**	**$ 122,993,150**
Work In Progress	-	-	-	-	-	-
TOTAL ACCUM DEPRECIATION INCLUDING WIP	**$ 89,104,901**	**$ 85,365,493**	**$ 92,913,946**	**$ 106,035,180**	**$ 114,382,008**	**$ 122,993,150**
TOTAL NET BOOK VALUE FOR RATE BASE	**$ 113,576,899**	**$ 109,979,098**	**$ 138,746,635**	**$ 151,713,543**	**$ 155,061,461**	**$ 163,057,746**
Work In Progress	7,285,640	15,237,370	2,694,853	1,792,056	315,307	-
TOTAL NET BOOK VALUE INCLUDING WIP	**$ 120,862,539**	**$ 125,216,468**	**$ 141,441,488**	**$ 153,505,598**	**$ 155,376,768**	**$ 163,057,746**

Table 2-13 Fixed Asset Continuity Schedule, as at December 31st, 2010 including WIP

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	250,717	50,000	0	300,717	0	0	0	0	300,717
CEC	1806	Land Rights	0	0	0	0	0	0	0	0	0
47	1808	Buildings and Fixtures	829,700	0	0	829,700	205,273	20,072	0	225,345	604,355
13	1810	Leasehold Improvements	1,988,609	232,211	0	2,220,820	364,159	210,471	0	574,630	1,646,190
47	1815	Transformer Station Equipment - Normally Prim	0	0	0	0	0	0	0	0	0
47	1820	Distribution Station Equipment - Normally Prima	5,470,586	1,025,404	0	6,495,990	1,777,457	269,241	0	2,046,698	4,449,292
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	12,542,121	3,165,313	0	15,707,434	3,949,400	521,636	0	4,471,036	11,236,398
47	1835	Overhead Conductors and Devices	24,070,676	2,456,314	0	26,526,991	8,353,410	1,186,993	0	9,540,403	16,986,587
47	1840	Underground Conduit	50,700,928	2,807,796	0	53,508,724	19,184,096	2,369,295	0	21,553,391	31,955,332
47	1845	Underground Conductors and Devices	34,527,325	4,658,742	0	39,186,068	12,283,913	1,799,967	0	14,083,880	25,102,187
47	1850	Line Transformers	38,653,376	2,572,543	0	41,225,919	14,666,288	1,848,514	0	16,514,802	24,711,117
47	1855	Services	5,891,912	1,177,838	0	7,069,750	545,608	259,323	0	804,931	6,264,819
47	1860	Meters	9,845,892	886,487	4,661,950	6,070,429	4,025,648	638,875	1,866,700	2,797,823	3,272,606
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	0	0	0	0	0	0	0	0	0
CEC	1906	Land Rights	0	0	0	0	0	0	0	0	0
47	1908	Buildings and Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	848,851	15,305	0	864,156	668,793	27,852	0	696,645	167,512
10	1920	Computer Equipment - Hardware	4,608,482	387,074	0	4,995,556	4,143,680	355,401	0	4,499,081	496,476
12	1925	Computer Software	3,729,610	443,330	0	4,172,940	2,968,761	569,478	0	3,538,239	634,701
10	1930	Transportation Equipment	3,396,621	39,905	0	3,436,526	1,409,312	378,288	0	1,787,600	1,648,926
8	1935	Stores Equipment	155,867	0	0	155,867	146,897	1,086	0	147,983	7,884
8	1940	Tools, Shop and Garage Equipment	1,081,917	129,233	0	1,211,150	602,761	82,742	0	685,503	525,647
8	1945	Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	5,200	0	0	5,200	1,253	520	0	1,773	3,427
47	1970	Load Management Controls - Customer Premis	171,648	0	0	171,648	171,648	0	0	171,648	0
47	1975	Load Management Controls - Utility Premises	49,876	0	0	49,876	49,876	0	0	49,876	0
47	1980	System Supervisory Equipment	3,390,312	311,332	0	3,701,644	1,809,368	177,135	0	1,986,503	1,715,141
47	1985	Sentinel Lighting Rentals	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 and Grants	(30,508,383)	(3,743,516)	0	(34,251,899)	(5,909,245)	(1,306,939)	0	(7,216,184)	(27,035,715)
	2005	Property under Capital Lease	13,122,519	0	1,433,134	11,689,385	7,250,101	586,920	1,433,134	6,403,887	5,285,498
		Total before Work in Process	**184,824,364**	**16,615,311**	**6,095,084**	**195,344,591**	**78,668,456**	**9,996,871**	**3,299,834**	**85,365,493**	**109,979,098**
WIP	2055	Work in Process	4,843,540	10,393,831		15,237,370	0			0	15,237,370
		Total after Work in Process	**189,667,903**	**27,009,142**	**6,095,084**	**210,581,961**	**78,668,456**	**9,996,871**	**3,299,834**	**85,365,493**	**125,216,468**

Table 2-14 Fixed Asset Continuity Schedule, as at December 31st, 2011 including WIP

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	300,717	1,421,336	0	1,722,054	0	0	0	0	1,722,054
CEC	1806	Land Rights	0	0	0	0	0	0	0	0	0
47	1808	Buildings and Fixtures	829,700	0	0	829,700	225,345	20,074	0	245,418	584,281
13	1810	Leasehold Improvements	2,220,820	1,073,323	0	3,294,143	574,630	275,748	0	850,378	2,443,765
47	1815	Transformer Station Equipment - Normally Prima	0	21,439,242	0	21,439,242	0	215,137	0	215,137	21,224,105
47	1820	Distribution Station Equipment - Normally Prima	6,495,990	120,595	0	6,616,585	2,046,698	250,424	0	2,297,122	4,319,464
47	1825	Storage Battery Equipment	0	0	0	0	0	0	0	0	0
47	1830	Poles, Towers and Fixtures	15,707,434	3,965,353	0	19,672,787	4,471,036	681,691	0	5,152,726	14,520,061
47	1835	Overhead Conductors and Devices	26,526,991	3,407,701	0	29,934,691	9,540,403	1,268,620	0	10,809,023	19,125,668
47	1840	Underground Conduit	53,508,724	3,158,132	0	56,666,855	21,553,391	2,430,505	0	23,983,897	32,682,959
47	1845	Underground Conductors and Devices	39,186,068	4,317,293	0	43,503,361	14,083,880	1,967,608	0	16,051,488	27,451,872
47	1850	Line Transformers	41,225,919	1,780,756	174,016	42,832,659	16,514,802	1,852,593	0	18,367,395	24,465,264
47	1855	Services	7,069,750	1,428,385	0	8,498,135	804,931	311,447	0	1,116,379	7,381,757
47	1860	Meters	6,070,429	255,748	3,551,434	2,774,743	2,797,823	95,871	2,646,728	246,966	2,527,778
N/A	1865	Other Installations on Customer's Premises	0	0	0	0	0	0	0	0	0
N/A	1905	Land	0	0	0	0	0	0	0	0	0
CEC	1906	Land Rights	0	0	0	0	0	0	0	0	0
47	1908	Buildings and Fixtures	0	0	0	0	0	0	0	0	0
13	1910	Leasehold Improvements	0	0	0	0	0	0	0	0	0
8	1915	Office Furniture and Equipment	864,156	6,729	0	870,885	696,645	27,831	0	724,476	146,409
10	1920	Computer Equipment - Hardware	4,995,556	1,629,480	0	6,625,036	4,499,081	574,519	0	5,073,599	1,551,437
12	1925	Computer Software	4,172,940	0	0	4,172,940	3,538,239	413,036	0	3,951,275	221,665
10	1930	Transportation Equipment	3,436,526	468,107	5,000	3,899,634	1,787,600	399,120	0	2,186,721	1,712,913
8	1935	Stores Equipment	155,867	0	0	155,867	147,983	1,086	0	149,070	6,798
8	1940	Tools, Shop and Garage Equipment	1,211,150	25,613	0	1,236,763	685,503	90,485	0	775,988	460,775
8	1945	Measurement and Testing Equipment	0	0	0	0	0	0	0	0	0
8	1950	Power Operated Equipment	0	0	0	0	0	0	0	0	0
8	1955	Communication Equipment	0	0	0	0	0	0	0	0	0
8	1960	Miscellaneous Equipment	5,200	2,898	0	8,098	1,773	665	0	2,438	5,660
47	1970	Load Management Controls - Customer Premise	171,648	0	0	171,648	171,648	0	0	171,648	0
47	1975	Load Management Controls - Utility Premises	49,876	0	0	49,876	49,876	0	0	49,876	0
47	1980	System Supervisory Equipment	3,701,644	258,738	0	3,960,382	1,986,503	196,137	0	2,182,640	1,777,742
47	1985	Sentinel Lighting Rentals	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 and Grants	(34,251,899)	(4,712,987)	0	(38,964,886)	(7,216,184)	(1,464,336)	0	(8,680,520)	(30,284,366)
	2005	Property under Capital Lease	11,689,385	0	0	11,689,385	6,403,887	586,920	0	6,990,807	4,698,577
		Total before Work in Process	**195,344,591**	**40,046,440**	**3,730,450**	**231,660,581**	**85,365,493**	**10,195,182**	**2,646,728**	**92,913,946**	**138,746,635**
WIP	2055	Work in Process	15,237,370	47,092,221	59,634,738	2,694,853	0	0	0	0	2,694,853
		Total after Work in Process	**210,581,961**	**87,138,662**	**63,365,188**	**234,355,434**	**85,365,493**	**10,195,182**	**2,646,728**	**92,913,946**	**141,441,488**

Table 2-15 Fixed Asset Continuity Schedule, as at December 31st, 2012 (CGAAP) including WIP

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	1,722,054			1,722,054	0			0	1,722,054
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	829,700			829,700	245,418	20,126		265,544	564,155
13	1810	Leasehold Improvements	3,294,143	211,332		3,505,475	850,378	339,981		1,190,359	2,315,116
47	1815	Transformer Station Equipment - Normally Prima	21,439,242	162,960		21,602,201	215,137	432,147		647,283	20,954,918
47	1820	Distribution Station Equipment - Normally Primar	6,616,585	694,157		7,310,742	2,297,122	261,753		2,558,874	4,751,868
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	19,672,787	2,874,598		22,547,385	5,152,726	806,444		5,959,170	16,588,215
47	1835	Overhead Conductors and Devices	29,934,691	1,857,172		31,791,864	10,809,023	1,339,101		12,148,124	19,643,740
47	1840	Underground Conduit	56,666,855	3,779,911		60,446,766	23,983,897	2,471,535		26,455,432	33,991,334
47	1845	Underground Conductors and Devices	43,503,361	2,577,515		46,080,876	16,051,488	1,938,720		17,990,209	28,090,667
47	1850	Line Transformers	42,832,659	2,084,014		44,916,673	18,367,395	1,848,010		20,215,405	24,701,268
47	1855	Services	8,498,135	1,186,763		9,684,898	1,116,379	363,661		1,480,039	8,204,859
47	1860	Meters	2,774,743	10,160,322		12,935,065	246,966	1,930,919		2,177,884	10,757,181
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	870,885	1,303		872,187	724,476	26,018		750,494	121,694
10	1920	Computer Equipment - Hardware	6,625,036	745,975		7,371,011	5,073,599	920,588		5,994,187	1,376,823
12	1925	Computer Software	4,172,940	1,113,652		5,286,592	3,951,275	444,353		4,395,627	890,964
10	1930	Transportation Equipment	3,899,634	839,811	251,092	4,488,353	2,186,721	492,548	239,310	2,439,959	2,048,394
8	1935	Stores Equipment	155,867	10,466		166,334	149,070	1,610		150,679	15,654
8	1940	Tools, Shop and Garage Equipment	1,236,763	42,443		1,279,206	775,988	90,784		866,772	412,434
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	8,098			8,098	2,438	810		3,248	4,850
47	1970	Load Management Controls - Customer Premise	171,648			171,648	171,648			171,648	0
47	1975	Load Management Controls - Utility Premises	49,876			49,876	49,876			49,876	0
47	1980	System Supervisory Equipment	3,960,382	526,238		4,486,620	2,182,640	198,535		2,381,175	2,105,445
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(38,964,886)	(4,872,160)	(2,342,761)	(41,494,285)	(8,680,520)	(1,155,625)		(9,836,144)	(31,658,140)
	2005	Property under Capital Lease	11,689,385			11,689,385	6,990,807	588,528		7,579,335	4,110,049
		Total before Work in Process	**231,660,581**	**23,996,472**	**(2,091,669)**	**257,748,723**	**92,913,946**	**13,360,543**	**239,310**	**106,035,180**	**151,713,543**
WIP	2055	Work in Process	2,694,853	34,547,220	35,450,018	1,792,056	0			0	1,792,056
		Total after Work in Process	**234,355,434**	**58,543,692**	**33,358,348**	**259,540,778**	**92,913,946**	**13,360,543**	**239,310**	**106,035,180**	**153,505,598**

Table 2-16 Fixed Asset Continuity Schedule, as at December 31st, 2013 (Old CGAAP) including WIP

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	1,722,054			1,722,054	0			0	1,722,054
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	829,700			829,700	265,544	20,073		285,617	544,083
13	1810	Leasehold Improvements	3,505,475	72,500		3,577,975	1,190,359	354,173		1,544,532	2,033,444
47	1815	Transformer Station Equipment - Normally Prima	21,602,201	70,282		21,672,483	647,283	635,637		1,282,921	20,389,563
47	1820	Distribution Station Equipment - Normally Prima	7,310,742	608,156		7,918,899	2,558,874	281,283		2,840,157	5,078,741
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	22,547,385	2,664,937		25,212,322	5,959,170	906,014		6,865,185	18,347,137
47	1835	Overhead Conductors and Devices	31,791,864	1,643,509		33,435,373	12,148,124	1,321,573		13,469,697	19,965,676
47	1840	Underground Conduit	60,446,766	3,621,801		64,068,567	26,455,432	2,556,960		29,012,392	35,056,175
47	1845	Underground Conductors and Devices	46,080,876	4,597,350		50,678,225	17,990,209	1,991,093		19,981,302	30,696,923
47	1850	Line Transformers	44,916,673	2,167,544		47,084,217	20,215,405	1,838,004		22,053,410	25,030,808
47	1855	Services	9,684,898	849,542		10,534,440	1,480,039	404,387		1,884,426	8,650,014
47	1860	Meters	12,935,065	479,202		13,414,267	2,177,884	786,824		2,964,708	10,449,559
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	872,187			872,187	750,494	23,865		774,359	97,829
10	1920	Computer Equipment - Hardware	7,371,011	438,500		7,809,511	5,994,187	929,839		6,924,026	885,485
12	1925	Computer Software	5,286,592	1,086,974		6,373,566	4,395,627	405,316		4,800,943	1,572,622
10	1930	Transportation Equipment	4,488,353	638,008		5,126,361	2,439,959	569,003		3,008,961	2,117,400
8	1935	Stores Equipment	166,334			166,334	150,679	2,133		152,812	13,521
8	1940	Tools, Shop and Garage Equipment	1,279,206	115,439		1,394,645	866,772	98,593		965,365	429,280
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	8,098			8,098	3,248	810		4,058	4,040
47	1970	Load Management Controls - Customer Premise	171,648			171,648	171,648	0		171,648	0
47	1975	Load Management Controls - Utility Premises	49,876			49,876	49,876	0		49,876	0
47	1980	System Supervisory Equipment	4,486,620	244,000		4,730,620	2,381,175	266,741		2,647,916	2,082,703
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(41,494,285)	(4,289,005)		(45,783,290)	(9,836,144)	(1,745,551)		(11,581,696)	(34,201,594)
	2005	Property under Capital Lease	11,689,385			11,689,385	7,579,335	241,768		7,821,103	3,868,282
		Total before Work in Process	**257,748,723**	**15,008,738**	**0**	**272,757,460**	**106,035,180**	**11,888,537**	**0**	**117,923,717**	**154,833,743**
WIP	2055	Work in Process	1,792,056	(1,376,935)		415,121	0			0	415,121
		Total after Work in Process	**259,540,778**	**13,631,803**	**0**	**273,172,581**	**106,035,180**	**11,888,537**	**0**	**117,923,717**	**155,248,864**

Table 2-17 Fixed Asset Continuity Schedule, as at December 31st, 2013 (New CGAAP) including WIP

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	1,722,054			1,722,054	0			0	1,722,054
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	829,700			829,700	265,544	20,299		285,843	543,857
13	1810	Leasehold Improvements	3,505,475	66,046		3,571,521	1,190,359	353,850		1,544,209	2,027,312
47	1815	Transformer Station Equipment - Normally Prima	21,602,201	61,115		21,663,316	647,283	505,223		1,152,507	20,510,810
47	1820	Distribution Station Equipment - Normally Prima	7,310,742	497,773		7,808,516	2,558,874	577,554		3,136,428	4,672,087
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	22,547,385	1,765,679		24,313,064	5,959,170	428,003		6,387,173	17,925,891
47	1835	Overhead Conductors and Devices	31,791,864	1,012,210		32,804,074	12,148,124	553,538		12,701,662	20,102,412
47	1840	Underground Conduit	60,446,766	2,915,414		63,362,180	26,455,432	959,212		27,414,644	35,947,536
47	1845	Underground Conductors and Devices	46,080,876	3,596,714		49,677,590	17,990,209	1,283,772		19,273,981	30,403,609
47	1850	Line Transformers	44,916,673	1,718,934		46,635,608	20,215,405	955,669		21,171,075	25,464,533
47	1855	Services	9,684,898	635,533		10,320,431	1,480,039	212,547		1,692,587	8,627,844
47	1860	Meters	12,935,065	362,879		13,297,944	2,177,884	1,324,174		3,502,058	9,795,886
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	872,187			872,187	750,494	23,865		774,359	97,829
10	1920	Computer Equipment - Hardware	7,371,011	438,500		7,809,511	5,994,187	607,291		6,601,478	1,208,033
12	1925	Computer Software	5,286,592	1,062,977		6,349,568	4,395,627	379,393		4,775,020	1,574,548
10	1930	Transportation Equipment	4,488,353	583,203		5,071,556	2,439,959	346,046		2,786,005	2,285,551
8	1935	Stores Equipment	166,334			166,334	150,679	2,133		152,812	13,521
8	1940	Tools, Shop and Garage Equipment	1,279,206	107,902		1,387,108	866,772	187,319		1,054,091	333,017
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	8,098			8,098	3,248	810		4,058	4,040
47	1970	Load Management Controls - Customer Premise	171,648			171,648	171,648	0		171,648	0
47	1975	Load Management Controls - Utility Premises	49,876			49,876	49,876	0		49,876	0
47	1980	System Supervisory Equipment	4,486,620	184,948		4,671,567	2,381,175	269,694		2,650,869	2,020,698
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(41,494,285)	(3,315,080)		(44,809,365)	(9,836,144)	(885,330)		(10,721,475)	(34,087,890)
	2005	Property under Capital Lease	11,689,385			11,689,385	7,579,335	241,768		7,821,103	3,868,282
		Total before Work in Process	**257,748,723**	**11,694,747**	**0**	**269,443,469**	**106,035,180**	**8,346,829**	**0**	**114,382,008**	**155,061,461**
WIP	2055	Work in Process	1,792,056	(1,476,748)		315,307	0			0	315,307
		Total after Work in Process	**259,540,778**	**10,217,999**	**0**	**269,758,777**	**106,035,180**	**8,346,829**	**0**	**114,382,008**	**155,376,768**

Table 2-18 Fixed Asset Continuity Schedule, as at December 31st, 2014 (New CGAAP) including WIP

			Cost				Accumulated Depreciation				
CCA Class	OEB	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
N/A	1805	Land	1,722,054			1,722,054	0			0	1,722,054
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	829,700			829,700	285,843	20,299		306,142	523,558
13	1810	Leasehold Improvements	3,571,521	341,615		3,913,136	1,544,209	374,233		1,918,442	1,994,694
47	1815	Transformer Station Equipment - Normally Prima	21,663,316			21,663,316	1,152,507	507,260		1,659,767	20,003,549
47	1820	Distribution Station Equipment - Normally Prima	7,808,516	678,906		8,487,422	3,136,428	302,804		3,439,233	5,048,189
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	24,313,064	1,296,190		25,609,254	6,387,173	462,024		6,849,196	18,760,057
47	1835	Overhead Conductors and Devices	32,804,074	770,811		33,574,885	12,701,662	565,217		13,266,878	20,308,007
47	1840	Underground Conduit	63,362,180	2,411,768		65,773,948	27,414,644	967,615		28,382,259	37,391,689
47	1845	Underground Conductors and Devices	49,677,590	3,552,079		53,229,669	19,273,981	1,312,571		20,586,551	32,643,117
47	1850	Line Transformers	46,635,608	6,757,281		53,392,889	21,171,075	1,059,136		22,230,211	31,162,678
47	1855	Services	10,320,431	641,411		10,961,842	1,692,587	227,333		1,919,920	9,041,922
47	1860	Meters	13,297,944	481,706		13,779,651	3,502,058	1,347,647		4,849,704	8,929,946
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	872,187			872,187	774,359	23,865		798,224	73,963
10	1920	Computer Equipment - Hardware	7,809,511	380,000		8,189,511	6,601,478	688,714		7,290,191	899,319
12	1925	Computer Software	6,349,568	1,231,000		7,580,568	4,775,020	639,742		5,414,761	2,165,807
10	1930	Transportation Equipment	5,071,556	384,762		5,456,318	2,786,005	392,376		3,178,381	2,277,937
8	1935	Stores Equipment	166,334			166,334	152,812	2,133		154,945	11,389
8	1940	Tools, Shop and Garage Equipment	1,387,108	93,333		1,480,441	1,054,091	126,914		1,181,005	299,437
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	8,098			8,098	4,058	810		4,868	3,231
47	1970	Load Management Controls - Customer Premise	171,648			171,648	171,648	0		171,648	0
47	1975	Load Management Controls - Utility Premises	49,876			49,876	49,876	0		49,876	0
47	1980	System Supervisory Equipment	4,671,567	147,635		4,819,203	2,650,869	271,238		2,922,107	1,897,095
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(44,809,365)	(3,299,281)		(48,108,646)	(10,721,475)	(967,295)		(11,688,770)	(36,419,876)
13	2005	Property under Capital Lease	11,689,385	738,210		12,427,595	7,821,103	286,508		8,107,610	4,319,984
		Total before Work in Process	**269,443,469**	**16,607,427**	**0**	**286,050,896**	**114,382,008**	**8,611,141**	**0**	**122,993,150**	**163,057,746**
WIP	2055	Work in Process	315,307	(315,307)		0	0			0	0
		Total after Work in Process	**269,758,777**	**16,292,119**	**0**	**286,050,896**	**114,382,008**	**8,611,141**	**0**	**122,993,150**	**163,057,746**

Fixed Asset Continuity Schedules Excluding Work-in-Progress

Oakville Hydro is filing the Board's Fixed Asset Continuity Schedules, Appendix 2-BA1 Fixed Asset Continuity Schedule (CGAAP/ASPE/USGAAP). These continuity schedules exclude Work-In-Progress as per the Board's filing requirements, and as such are filed in addition to the continuity schedules provided in Tables 2-13 through 2-18.

Appendix 2-BA (Excluding WIP)
Fixed Asset Continuity Schedule - CGAAP

Year **2010**

			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)	$ 3,729,610	$ 443,330	$ -	$ 4,172,940	-$ 2,968,761	-$ 569,478	$ -	-$ 3,538,239	$ 634,701
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 250,717	$ 50,000	$ -	$ 300,717	$ -	$ -	$ -	$ -	$ 300,717
47	1808	Buildings	$ 829,700	$ -	$ -	$ 829,700	-$ 205,273	-$ 20,072	$ -	-$ 225,345	$ 604,355
13	1810	Leasehold Improvements	$ 1,988,609	$ 232,211	$ -	$ 2,220,820	-$ 364,159	-$ 210,471	$ -	-$ 574,630	$ 1,646,190
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 5,470,586	$ 1,025,404	$ -	$ 6,495,990	-$ 1,777,457	-$ 269,241	$ -	-$ 2,046,698	$ 4,449,292
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 12,542,121	$ 3,165,313	$ -	$ 15,707,434	-$ 3,949,400	-$ 521,636	$ -	-$ 4,471,036	$ 11,236,398
47	1835	Overhead Conductors & Devices	$ 24,070,676	$ 2,456,314	$ -	$ 26,526,991	-$ 8,353,410	-$ 1,186,993	$ -	-$ 9,540,403	$ 16,986,587
47	1840	Underground Conduit	$ 50,700,928	$ 2,807,796	$ -	$ 53,508,724	-$ 19,184,096	-$ 2,369,295	$ -	-$ 21,553,391	$ 31,955,332
47	1845	Underground Conductors & Devices	$ 34,527,325	$ 4,658,742	$ -	$ 39,186,068	-$ 12,283,913	-$ 1,799,967	$ -	-$ 14,083,880	$ 25,102,187
47	1850	Line Transformers	$ 38,653,376	$ 2,572,543	$ -	$ 41,225,919	-$ 14,666,288	-$ 1,848,514	$ -	-$ 16,514,802	$ 24,711,117
47	1855	Services (Overhead & Underground)	$ 5,891,912	$ 1,177,838	$ -	$ 7,069,750	-$ 545,608	-$ 259,323	$ -	-$ 804,931	$ 6,264,819
47	1860	Meters	$ 8,756,933	$ 752,095	-$ 4,661,950	$ 4,847,078	-$ 3,927,103	-$ 592,624	$ 1,866,700	-$ 2,653,026	$ 2,194,052
47	1860	Meters (Smart Meters)	$ 1,088,959	$ 134,391	$ -	$ 1,223,351	-$ 98,546	-$ 46,251	$ -	-$ 144,797	$ 1,078,554
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 848,851	$ 15,305	$ -	$ 864,156	-$ 668,793	-$ 27,852	$ -	-$ 696,645	$ 167,512
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 1,549,782			$ 1,549,782	-$ 1,549,782			-$ 1,549,782	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ 479,325			$ 479,325	-$ 479,325			-$ 479,325	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 2,579,375	$ 387,074		$ 2,966,449	-$ 2,114,572	-$ 355,401		-$ 2,469,973	$ 496,476
10	1930	Transportation Equipment	$ 3,396,621	$ 39,905	$ -	$ 3,436,526	-$ 1,409,312	-$ 378,288	$ -	-$ 1,787,600	$ 1,648,926
8	1935	Stores Equipment	$ 155,867	$ -	$ -	$ 155,867	-$ 146,897	-$ 1,086	$ -	-$ 147,983	$ 7,884
8	1940	Tools, Shop & Garage Equipment	$ 1,081,917	$ 129,233	$ -	$ 1,211,150	-$ 602,761	-$ 82,742	$ -	-$ 685,503	$ 525,647
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 5,200	$ -	$ -	$ 5,200	-$ 1,253	-$ 520	$ -	-$ 1,773	$ 3,427
47	1970	Load Management Controls Customer Premises	$ 171,648	$ -	$ -	$ 171,648	-$ 171,648	$ -	$ -	-$ 171,648	$ -
47	1975	Load Management Controls Utility Premises	$ 49,876	$ -	$ -	$ 49,876	-$ 49,876	$ -	$ -	-$ 49,876	$ -
47	1980	System Supervisor Equipment	$ 3,390,312	$ 311,332	$ -	$ 3,701,644	-$ 1,809,368	-$ 177,135	$ -	-$ 1,986,503	$ 1,715,141
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 30,508,383	-$ 3,743,516	$ -	-$ 34,251,899	$ 5,909,245	$ 1,306,939	$ -	$ 7,216,184	-$ 27,035,715
	2005	Property Under Capital Lease	$ 13,122,519	$ -	-$ 1,433,134	$ 11,689,385	-$ 7,250,101	-$ 586,920	$ 1,433,134	-$ 6,403,887	$ 5,285,498
						$ -				$ -	$ -
		Sub-Total	**$ 184,824,364**	**$ 16,615,311**	**-$ 6,095,084**	**$ 195,344,591**	**-$ 78,668,456**	**-$ 9,996,871**	**$ 3,299,834**	**-$ 85,365,493**	**$ 109,979,098**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 184,824,364**	**$ 16,615,311**	**-$ 6,095,084**	**$ 195,344,591**	**-$ 78,668,456**	**-$ 9,996,871**	**$ 3,299,834**	**-$ 85,365,493**	**$ 109,979,098**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*
Transportation
Stores Equipment
Net Depreciation -$ 9,996,871

Appendix 2-BA (Excluding WIP)
Fixed Asset Continuity Schedule - CGAAP

Year **2011**

			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)	$ 4,172,940	$ -	$ -	$ 4,172,940	-$ 3,538,239	-$ 413,036	$ -	-$ 3,951,275	$ 221,665
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 300,717	$ 1,421,336	$ -	$ 1,722,054	$ -	$ -	$ -	$ -	$ 1,722,054
47	1808	Buildings	$ 829,700	$ -	$ -	$ 829,700	-$ 225,345	-$ 20,074	$ -	-$ 245,418	$ 584,281
13	1810	Leasehold Improvements	$ 2,220,820	$ 1,073,323	$ -	$ 3,294,143	-$ 574,630	-$ 275,748	$ -	-$ 850,378	$ 2,443,765
47	1815	Transformer Station Equipment >50 kV	$ -	$ 21,439,242	$ -	$ 21,439,242	$ -	-$ 215,137	$ -	-$ 215,137	$ 21,224,105
47	1820	Distribution Station Equipment <50 kV	$ 6,495,990	$ 120,595	$ -	$ 6,616,585	-$ 2,046,698	-$ 250,424	$ -	-$ 2,297,122	$ 4,319,464
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 15,707,434	$ 3,965,353	$ -	$ 19,672,787	-$ 4,471,036	-$ 681,691	$ -	-$ 5,152,726	$ 14,520,061
47	1835	Overhead Conductors & Devices	$ 26,526,991	$ 3,407,701	$ -	$ 29,934,691	-$ 9,540,403	-$ 1,268,620	$ -	-$ 10,809,023	$ 19,125,668
47	1840	Underground Conduit	$ 53,508,724	$ 3,158,132	$ -	$ 56,666,855	-$ 21,553,391	-$ 2,430,505	$ -	-$ 23,983,897	$ 32,682,959
47	1845	Underground Conductors & Devices	$ 39,186,068	$ 4,317,293	$ -	$ 43,503,361	-$ 14,083,880	-$ 1,967,608	$ -	-$ 16,051,488	$ 27,451,872
47	1850	Line Transformers	$ 41,225,919	$ 1,780,756	-$ 174,016	$ 42,832,659	-$ 16,514,802	-$ 1,852,593	$ -	-$ 18,367,395	$ 24,465,264
47	1855	Services (Overhead & Underground)	$ 7,069,750	$ 1,428,385	$ -	$ 8,498,135	-$ 804,931	-$ 311,447	$ -	-$ 1,116,379	$ 7,381,757
47	1860	Meters	$ 4,847,078	$ 116,678	-$ 3,551,434	$ 1,412,323	-$ 2,653,026	-$ 44,151	$ 2,646,728	-$ 50,449	$ 1,361,874
47	1860	Meters (Smart Meters)	$ 1,223,351	$ 139,070	$ -	$ 1,362,420	-$ 144,797	-$ 51,720	$ -	-$ 196,517	$ 1,165,903
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 864,156	$ 6,729	$ -	$ 870,885	-$ 696,645	-$ 27,831	$ -	-$ 724,476	$ 146,409
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 4,995,556	$ 1,629,480		$ 6,625,036	-$ 4,499,081	-$ 574,519		-$ 5,073,599	$ 1,551,437
10	1930	Transportation Equipment	$ 3,436,526	$ 468,107	-$ 5,000	$ 3,899,634	-$ 1,787,600	-$ 399,120	$ -	-$ 2,186,721	$ 1,712,913
8	1935	Stores Equipment	$ 155,867	$ -	$ -	$ 155,867	-$ 147,983	-$ 1,086	$ -	-$ 149,070	$ 6,798
8	1940	Tools, Shop & Garage Equipment	$ 1,211,150	$ 25,613	$ -	$ 1,236,763	-$ 685,503	-$ 90,485	$ -	-$ 775,988	$ 460,775
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 5,200	$ 2,898	$ -	$ 8,098	-$ 1,773	-$ 665	$ -	-$ 2,438	$ 5,660
47	1970	Load Management Controls Customer Premises	$ 171,648	$ -	$ -	$ 171,648	-$ 171,648	$ -	$ -	-$ 171,648	$ -
47	1975	Load Management Controls Utility Premises	$ 49,876	$ -	$ -	$ 49,876	-$ 49,876	$ -	$ -	-$ 49,876	$ -
47	1980	System Supervisor Equipment	$ 3,701,644	$ 258,738	$ -	$ 3,960,382	-$ 1,986,503	-$ 196,137	$ -	-$ 2,182,640	$ 1,777,742
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 34,251,899	-$ 4,712,987	$ -	-$ 38,964,886	$ 7,216,184	$ 1,464,336	$ -	$ 8,680,520	-$ 30,284,366
	2005	Property Under Capital Lease	$ 11,689,385	$ -	$ -	$ 11,689,385	-$ 6,403,887	-$ 586,920	$ -	-$ 6,990,807	$ 4,698,577
						$ -				$ -	$ -
		Sub-Total	**$ 195,344,591**	**$ 40,046,440**	**-$ 3,730,450**	**$ 231,660,581**	**-$ 85,365,493**	**-$ 10,195,182**	**$ 2,646,728**	**-$ 92,913,946**	**$ 138,746,635**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 195,344,591**	**$ 40,046,440**	**-$ 3,730,450**	**$ 231,660,581**	**-$ 85,365,493**	**-$ 10,195,182**	**$ 2,646,728**	**-$ 92,913,946**	**$ 138,746,635**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 10,195,182

Appendix 2-BA (Excluding WIP)
Fixed Asset Continuity Schedule - CGAAP

Year **2012**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 4,172,940	$ 1,113,652	$ -	$ 5,286,592	-$ 3,951,275	-$ 444,353	$ -	-$ 4,395,627	$ 890,964
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 1,722,054	$ -	$ -	$ 1,722,054	$ -	$ -	$ -	$ -	$ 1,722,054
47	1808	Buildings	$ 829,700	$ -	$ -	$ 829,700	-$ 245,418	-$ 20,126	$ -	-$ 265,544	$ 564,155
13	1810	Leasehold Improvements	$ 3,294,143	$ 211,332	$ -	$ 3,505,475	-$ 850,378	-$ 339,981	$ -	-$ 1,190,359	$ 2,315,116
47	1815	Transformer Station Equipment >50 kV	$ 21,439,242	$ 162,960	$ -	$ 21,602,201	-$ 215,137	-$ 432,147	$ -	-$ 647,283	$ 20,954,918
47	1820	Distribution Station Equipment <50 kV	$ 6,616,585	$ 694,157	$ -	$ 7,310,742	-$ 2,297,122	-$ 261,753	$ -	-$ 2,558,874	$ 4,751,868
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 19,672,787	$ 2,874,598	$ -	$ 22,547,385	-$ 5,152,726	-$ 806,444	$ -	-$ 5,959,170	$ 16,588,215
47	1835	Overhead Conductors & Devices	$ 29,934,691	$ 1,857,172	$ -	$ 31,791,864	-$ 10,809,023	-$ 1,339,101	$ -	-$ 12,148,124	$ 19,643,740
47	1840	Underground Conduit	$ 56,666,855	$ 3,779,911	$ -	$ 60,446,766	-$ 23,983,897	-$ 2,471,535	$ -	-$ 26,455,432	$ 33,991,334
47	1845	Underground Conductors & Devices	$ 43,503,361	$ 2,577,515	$ -	$ 46,080,876	-$ 16,051,488	-$ 1,938,720	$ -	-$ 17,990,209	$ 28,090,667
47	1850	Line Transformers	$ 42,832,659	$ 2,084,014	$ -	$ 44,916,673	-$ 18,367,395	-$ 1,848,010	$ -	-$ 20,215,405	$ 24,701,268
47	1855	Services (Overhead & Underground)	$ 8,498,135	$ 1,186,763	$ -	$ 9,684,898	-$ 1,116,379	-$ 363,661	$ -	-$ 1,480,039	$ 8,204,859
47	1860	Meters	$ 1,412,323	$ 489,219	$ -	$ 1,901,542	-$ 50,449	-$ 269,062	$ -	-$ 319,510	$ 1,582,032
47	1860	Meters (Smart Meters)	$ 1,362,420	$ 9,671,103	$ -	$ 11,033,523	-$ 196,517	-$ 1,661,857	$ -	-$ 1,858,374	$ 9,175,149
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 870,885	$ 1,303	$ -	$ 872,187	-$ 724,476	-$ 26,018	$ -	-$ 750,494	$ 121,694
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 6,625,036	$ 745,975	$ -	$ 7,371,011	-$ 5,073,599	-$ 920,588	$ -	-$ 5,994,187	$ 1,376,823
10	1930	Transportation Equipment	$ 3,899,634	$ 839,811	-$ 251,092	$ 4,488,353	-$ 2,186,721	-$ 253,238	$ -	-$ 2,439,959	$ 2,048,394
8	1935	Stores Equipment	$ 155,867	$ 10,466	$ -	$ 166,334	-$ 149,070	-$ 1,610	$ -	-$ 150,679	$ 15,654
8	1940	Tools, Shop & Garage Equipment	$ 1,236,763	$ 42,443	$ -	$ 1,279,206	-$ 775,988	-$ 90,784	$ -	-$ 866,772	$ 412,434
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 8,098	$ -	$ -	$ 8,098	-$ 2,438	-$ 810	$ -	-$ 3,248	$ 4,850
47	1970	Load Management Controls Customer Premises	$ 171,648	$ -	$ -	$ 171,648	-$ 171,648	$ -	$ -	-$ 171,648	$ -
47	1975	Load Management Controls Utility Premises	$ 49,876	$ -	$ -	$ 49,876	-$ 49,876	$ -	$ -	-$ 49,876	$ -
47	1980	System Supervisor Equipment	$ 3,960,382	$ 526,238	$ -	$ 4,486,620	-$ 2,182,640	-$ 198,535	$ -	-$ 2,381,175	$ 2,105,445
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 38,964,886	-$ 4,872,160	$ 2,342,761	-$ 41,494,285	$ 8,680,520	$ 1,155,625	$ -	$ 9,836,144	-$ 31,658,140
	2005	Property Under Capital Lease	$ 11,689,385	$ -	$ -	$ 11,689,385	-$ 6,990,807	-$ 588,528	$ -	-$ 7,579,335	$ 4,110,049
						$ -				$ -	$ -
		Sub-Total	**$ 231,660,581**	**$ 23,996,472**	**$ 2,091,669**	**$ 257,748,723**	**-$ 92,913,946**	**-$ 13,121,233**	**$ -**	**-$ 106,035,180**	**$ 151,713,543**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 231,660,581**	**$ 23,996,472**	**$ 2,091,669**	**$ 257,748,723**	**-$ 92,913,946**	**-$ 13,121,233**	**$ -**	**-$ 106,035,180**	**$ 151,713,543**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 13,121,233

Appendix 2-BA (Excluding WIP)
Fixed Asset Continuity Schedule - CGAAP

Year **2013** **OLD CGAAP**

CCA Class	OEB	Description	Cost: Opening Balance	Cost: Additions	Cost: Disposals	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 5,286,592	$ 1,086,974	$ -	$ 6,373,566	-$ 4,395,627	-$ 405,316	$ -	-$ 4,800,943	$ 1,572,622
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 1,722,054	$ -	$ -	$ 1,722,054	$ -	$ -	$ -	$ -	$ 1,722,054
47	1808	Buildings	$ 829,700	$ -	$ -	$ 829,700	-$ 265,544	-$ 20,073	$ -	-$ 285,617	$ 544,083
13	1810	Leasehold Improvements	$ 3,505,475	$ 72,500	$ -	$ 3,577,975	-$ 1,190,359	-$ 354,173	$ -	-$ 1,544,532	$ 2,033,444
47	1815	Transformer Station Equipment >50 kV	$ 21,602,201	$ 70,282	$ -	$ 21,672,483	-$ 647,283	-$ 635,637	$ -	-$ 1,282,921	$ 20,389,563
47	1820	Distribution Station Equipment <50 kV	$ 7,310,742	$ 608,156	$ -	$ 7,918,899	-$ 2,558,874	-$ 281,283	$ -	-$ 2,840,157	$ 5,078,741
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 22,547,385	$ 2,664,937	$ -	$ 25,212,322	-$ 5,959,170	-$ 906,014	$ -	-$ 6,865,185	$ 18,347,137
47	1835	Overhead Conductors & Devices	$ 31,791,864	$ 1,643,509	$ -	$ 33,435,373	-$ 12,148,124	-$ 1,321,573	$ -	-$ 13,469,697	$ 19,965,676
47	1840	Underground Conduit	$ 60,446,766	$ 3,621,801	$ -	$ 64,068,567	-$ 26,455,432	-$ 2,556,960	$ -	-$ 29,012,392	$ 35,056,175
47	1845	Underground Conductors & Devices	$ 46,080,876	$ 4,597,350	$ -	$ 50,678,225	-$ 17,990,209	-$ 1,991,093	$ -	-$ 19,981,302	$ 30,696,923
47	1850	Line Transformers	$ 44,916,673	$ 2,167,544	$ -	$ 47,084,217	-$ 20,215,405	-$ 1,838,004	$ -	-$ 22,053,410	$ 25,030,808
47	1855	Services (Overhead & Underground)	$ 9,684,898	$ 849,542	$ -	$ 10,534,440	-$ 1,480,039	-$ 404,387	$ -	-$ 1,884,426	$ 8,650,014
47	1860	Meters	$ 1,901,542	$ -	$ -	$ 1,901,542	-$ 319,510	-$ 76,062	$ -	-$ 395,572	$ 1,505,970
47	1860	Meters (Smart Meters)	$ 11,033,523	$ 479,202	$ -	$ 11,512,725	-$ 1,858,374	-$ 710,762	$ -	-$ 2,569,136	$ 8,943,589
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 872,187	$ -	$ -	$ 872,187	-$ 750,494	-$ 23,865	$ -	-$ 774,359	$ 97,829
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 7,371,011	$ 438,500	$ -	$ 7,809,511	-$ 5,994,187	-$ 929,839	$ -	-$ 6,924,026	$ 885,485
10	1930	Transportation Equipment	$ 4,488,353	$ 638,008	$ -	$ 5,126,361	-$ 2,439,959	-$ 569,003	$ -	-$ 3,008,961	$ 2,117,400
8	1935	Stores Equipment	$ 166,334	$ -	$ -	$ 166,334	-$ 150,679	-$ 2,133	$ -	-$ 152,812	$ 13,521
8	1940	Tools, Shop & Garage Equipment	$ 1,279,206	$ 115,439	$ -	$ 1,394,645	-$ 866,772	-$ 98,593	$ -	-$ 965,365	$ 429,280
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 8,098	$ -	$ -	$ 8,098	-$ 3,248	-$ 810	$ -	-$ 4,058	$ 4,040
47	1970	Load Management Controls Customer Premises	$ 171,648	$ -	$ -	$ 171,648	-$ 171,648	$ -	$ -	-$ 171,648	$ -
47	1975	Load Management Controls Utility Premises	$ 49,876	$ -	$ -	$ 49,876	-$ 49,876	$ -	$ -	-$ 49,876	$ -
47	1980	System Supervisor Equipment	$ 4,486,620	$ 244,000	$ -	$ 4,730,620	-$ 2,381,175	-$ 266,741	$ -	-$ 2,647,916	$ 2,082,703
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 41,494,285	-$ 4,289,005	$ -	-$ 45,783,290	$ 9,836,144	$ 1,745,551	$ -	$ 11,581,696	-$ 34,201,594
	2005	Property Under Capital Lease	$ 11,689,385	$ -	$ -	$ 11,689,385	-$ 7,579,335	-$ 241,768	$ -	-$ 7,821,103	$ 3,868,282
						$ -				$ -	$ -
		Sub-Total	**$ 257,748,723**	**$ 15,008,738**	**$ -**	**$ 272,757,460**	**-$ 106,035,180**	**-$ 11,888,537**	**$ -**	**-$ 117,923,717**	**$ 154,833,743**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 257,748,723**	**$ 15,008,738**	**$ -**	**$ 272,757,460**	**-$ 106,035,180**	**-$ 11,888,537**	**$ -**	**-$ 117,923,717**	**$ 154,833,743**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 11,888,537

Appendix 2-BA (Excluding WIP)
Fixed Asset Continuity Schedule - CGAAP

Year 2013 **NEW CGAAP**

			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)	$ 5,286,592	$ 1,062,977	$ -	$ 6,349,568	-$ 4,395,627	-$ 379,393	$ -	-$ 4,775,020	$ 1,574,548
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 1,722,054	$ -	$ -	$ 1,722,054	$ -	$ -	$ -	$ -	$ 1,722,054
47	1808	Buildings	$ 829,700	$ -	$ -	$ 829,700	-$ 265,544	-$ 20,299	$ -	-$ 285,843	$ 543,857
13	1810	Leasehold Improvements	$ 3,505,475	$ 66,046	$ -	$ 3,571,521	-$ 1,190,359	-$ 353,850	$ -	-$ 1,544,209	$ 2,027,312
47	1815	Transformer Station Equipment >50 kV	$ 21,602,201	$ 61,115	$ -	$ 21,663,316	-$ 647,283	-$ 505,223	$ -	-$ 1,152,507	$ 20,510,810
47	1820	Distribution Station Equipment <50 kV	$ 7,310,742	$ 497,773	$ -	$ 7,808,516	-$ 2,558,874	-$ 577,554	$ -	-$ 3,136,428	$ 4,672,087
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 22,547,385	$ 1,765,679	$ -	$ 24,313,064	-$ 5,959,170	-$ 428,003	$ -	-$ 6,387,173	$ 17,925,891
47	1835	Overhead Conductors & Devices	$ 31,791,864	$ 1,012,210	$ -	$ 32,804,074	-$ 12,148,124	-$ 553,538	$ -	-$ 12,701,662	$ 20,102,412
47	1840	Underground Conduit	$ 60,446,766	$ 2,915,414	$ -	$ 63,362,180	-$ 26,455,432	-$ 959,212	$ -	-$ 27,414,644	$ 35,947,536
47	1845	Underground Conductors & Devices	$ 46,080,876	$ 3,596,714	$ -	$ 49,677,590	-$ 17,990,209	-$ 1,283,772	$ -	-$ 19,273,981	$ 30,403,609
47	1850	Line Transformers	$ 44,916,673	$ 1,718,934	$ -	$ 46,635,608	-$ 20,215,405	-$ 955,669	$ -	-$ 21,171,075	$ 25,464,533
47	1855	Services (Overhead & Underground)	$ 9,684,898	$ 635,533	$ -	$ 10,320,431	-$ 1,480,039	-$ 212,547	$ -	-$ 1,692,587	$ 8,627,844
47	1860	Meters	$ 1,901,542	$ -	$ -	$ 1,901,542	-$ 319,510	-$ 75,510	$ -	-$ 395,020	$ 1,506,522
47	1860	Meters (Smart Meters)	$ 11,033,523	$ 362,879	$ -	$ 11,396,402	-$ 1,858,374	-$ 1,248,663	$ -	-$ 3,107,037	$ 8,289,365
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 872,187	$ -	$ -	$ 872,187	-$ 750,494	-$ 23,865	$ -	-$ 774,359	$ 97,829
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 7,371,011	$ 438,500	$ -	$ 7,809,511	-$ 5,994,187	-$ 607,291	$ -	-$ 6,601,478	$ 1,208,033
10	1930	Transportation Equipment	$ 4,488,353	$ 583,203	$ -	$ 5,071,556	-$ 2,439,959	-$ 346,046	$ -	-$ 2,786,005	$ 2,285,551
8	1935	Stores Equipment	$ 166,334	$ -	$ -	$ 166,334	-$ 150,679	-$ 2,133	$ -	-$ 152,812	$ 13,521
8	1940	Tools, Shop & Garage Equipment	$ 1,279,206	$ 107,902	$ -	$ 1,387,108	-$ 866,772	-$ 187,319	$ -	-$ 1,054,091	$ 333,017
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 8,098	$ -	$ -	$ 8,098	-$ 3,248	-$ 810	$ -	-$ 4,058	$ 4,040
47	1970	Load Management Controls Customer Premises	$ 171,648	$ -	$ -	$ 171,648	-$ 171,648	$ -	$ -	-$ 171,648	$ -
47	1975	Load Management Controls Utility Premises	$ 49,876	$ -	$ -	$ 49,876	-$ 49,876	$ -	$ -	-$ 49,876	$ -
47	1980	System Supervisor Equipment	$ 4,486,620	$ 184,948	$ -	$ 4,671,567	-$ 2,381,175	-$ 269,694	$ -	-$ 2,650,869	$ 2,020,698
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 41,494,285	-$ 3,315,080	$ -	-$ 44,809,365	$ 9,836,144	$ 885,330	$ -	$ 10,721,475	-$ 34,087,890
	2005	Property Under Capital Lease	$ 11,689,385	$ -	$ -	$ 11,689,385	-$ 7,579,335	-$ 241,768	$ -	-$ 7,821,103	$ 3,868,282
						$ -					
		Sub-Total	**$ 257,748,723**	**$ 11,694,747**	**$ -**	**$ 269,443,469**	**-$ 106,035,180**	**-$ 8,346,829**	**$ -**	**-$ 114,382,008**	**$ 155,061,461**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 257,748,723**	**$ 11,694,747**	**$ -**	**$ 269,443,469**	**-$ 106,035,180**	**-$ 8,346,829**	**$ -**	**-$ 114,382,008**	**$ 155,061,461**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Net Depreciation	-$ 8,346,829

Appendix 2-BA (Excluding WIP)
Fixed Asset Continuity Schedule - CGAAP

Year **2014**

			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)	$ 6,349,568	$ 1,231,000	$ -	$ 7,580,568	-$ 4,775,020	-$ 639,742	$ -	-$ 5,414,761	$ 2,165,807
CEC	1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1805	Land	$ 1,722,054	$ -	$ -	$ 1,722,054	$ -	$ -	$ -	$ -	$ 1,722,054
47	1808	Buildings	$ 829,700	$ -	$ -	$ 829,700	-$ 285,843	-$ 20,299	$ -	-$ 306,142	$ 523,558
13	1810	Leasehold Improvements	$ 3,571,521	$ 341,615	$ -	$ 3,913,136	-$ 1,544,209	-$ 374,233	$ -	-$ 1,918,442	$ 1,994,694
47	1815	Transformer Station Equipment >50 kV	$ 21,663,316	$ -	$ -	$ 21,663,316	-$ 1,152,507	-$ 507,260	$ -	-$ 1,659,767	$ 20,003,549
47	1820	Distribution Station Equipment <50 kV	$ 7,808,516	$ 678,906	$ -	$ 8,487,422	-$ 3,136,428	-$ 302,804	$ -	-$ 3,439,233	$ 5,048,189
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 24,313,064	$ 1,296,190	$ -	$ 25,609,254	-$ 6,387,173	-$ 462,024	$ -	-$ 6,849,196	$ 18,760,057
47	1835	Overhead Conductors & Devices	$ 32,804,074	$ 770,811	$ -	$ 33,574,885	-$ 12,701,662	-$ 565,217	$ -	-$ 13,266,878	$ 20,308,007
47	1840	Underground Conduit	$ 63,362,180	$ 2,411,768	$ -	$ 65,773,948	-$ 27,414,644	-$ 967,615	$ -	-$ 28,382,259	$ 37,391,689
47	1845	Underground Conductors & Devices	$ 49,677,590	$ 3,552,079	$ -	$ 53,229,669	-$ 19,273,981	-$ 1,312,571	$ -	-$ 20,586,551	$ 32,643,117
47	1850	Line Transformers	$ 46,635,608	$ 6,757,281	$ -	$ 53,392,889	-$ 21,171,075	-$ 1,059,136	$ -	-$ 22,230,211	$ 31,162,678
47	1855	Services (Overhead & Underground)	$ 10,320,431	$ 641,411	$ -	$ 10,961,842	-$ 1,692,587	-$ 227,333	$ -	-$ 1,919,920	$ 9,041,922
47	1860	Meters	$ 1,901,542	$ -	$ -	$ 1,901,542	-$ 395,020	-$ 75,510	$ -	-$ 470,530	$ 1,431,011
47	1860	Meters (Smart Meters)	$ 11,396,402	$ 481,706	$ -	$ 11,878,109	-$ 3,107,037	-$ 1,272,136	$ -	-$ 4,379,174	$ 7,498,935
N/A	1905	Land	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 872,187	$ -	$ -	$ 872,187	-$ 774,359	-$ 23,865	$ -	-$ 798,224	$ 73,963
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 7,809,511	$ 380,000	$ -	$ 8,189,511	-$ 6,601,478	-$ 688,714	$ -	-$ 7,290,191	$ 899,319
10	1930	Transportation Equipment	$ 5,071,556	$ 384,762	$ -	$ 5,456,318	-$ 2,786,005	-$ 392,376	$ -	-$ 3,178,381	$ 2,277,937
8	1935	Stores Equipment	$ 166,334	$ -	$ -	$ 166,334	-$ 152,812	-$ 2,133	$ -	-$ 154,945	$ 11,389
8	1940	Tools, Shop & Garage Equipment	$ 1,387,108	$ 93,333	$ -	$ 1,480,441	-$ 1,054,091	-$ 126,914	$ -	-$ 1,181,005	$ 299,437
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 8,098	$ -	$ -	$ 8,098	-$ 4,058	-$ 810	$ -	-$ 4,868	$ 3,231
47	1970	Load Management Controls Customer Premises	$ 171,648	$ -	$ -	$ 171,648	-$ 171,648	$ -	$ -	-$ 171,648	$ -
47	1975	Load Management Controls Utility Premises	$ 49,876	$ -	$ -	$ 49,876	-$ 49,876	$ -	$ -	-$ 49,876	$ -
47	1980	System Supervisor Equipment	$ 4,671,567	$ 147,635	$ -	$ 4,819,203	-$ 2,650,869	-$ 271,238	$ -	-$ 2,922,107	$ 1,897,095
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 44,809,365	-$ 3,299,281	$ -	-$ 48,108,646	$ 10,721,475	$ 967,295	$ -	$ 11,688,770	-$ 36,419,876
	2005	Property Under Capital Lease	$ 11,689,385	$ 738,210	$ -	$ 12,427,595	-$ 7,821,103	-$ 286,508	$ -	-$ 8,107,610	$ 4,319,984
		Sub-Total	**$ 269,443,469**	**$ 16,607,427**	**$ -**	**$ 286,050,896**	**-$ 114,382,008**	**-$ 8,611,141**	**$ -**	**-$ 122,993,150**	**$ 163,057,746**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 269,443,469**	**$ 16,607,427**	**$ -**	**$ 286,050,896**	**-$ 114,382,008**	**-$ 8,611,141**	**$ -**	**-$ 122,993,150**	**$ 163,057,746**

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	-$ 8,611,141

Gross Property, Plant & Equipment and Accumulated Amortization

Breakdown by Function

As illustrated in Table 2-19, Oakville Hydro's assets are divided into three categories; distribution plant, general plant and other capital assets. In accordance with the Uniform System of Accounts, Oakville Hydro has included asset accounts 1805 to 1860 in the category of distribution plant, accounts 1915 to 1990 in the category of general plant and account 2005 in the category of other capital assets.

In addition, Oakville Hydro's distribution plant assets include a transmission asset that has been deemed to be a distribution asset. In its Decision and Order in Oakville Hydro's 2011 IRM application for an order or orders approving or fixing just and reasonable distribution rates and other charges, EB-2010-0104, the Accounting Standard Board approved Oakville Hydro's request to have the Glenorchy Municipal Transformer Station to be defined as a distribution asset pursuant to section 84(a) of the *Ontario Energy Board Act*.

Detailed amounts categorized according to the Board's Uniform System of Accounts ("USofA") are provided in Table 2-20 of this Exhibit.

Table 2-19 – Gross Assets Breakdown by Function

Gross Assets	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge Old CGAAP	2013 Bridge CGAAP	2014 Test
REPORTING BASIS	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Distribution Plant	$ 203,121,629	$ 199,142,542	$ 237,784,955	$ 263,373,699	$ 280,148,521	$ 276,005,996	$ 292,937,763
General Plant	20,026,384	18,764,563	21,151,128	24,179,924	26,702,845	26,557,453	28,794,184
Contributions and Grants	(33,612,886)	(34,251,899)	(38,964,886)	(41,494,285)	(45,783,290)	(44,809,365)	(48,108,646)
Other Capital Assets	13,146,673	11,689,385	11,689,385	11,689,385	11,689,385	11,689,385	12,427,595
TOTAL BEFORE WIP	**202,681,800**	**195,344,591**	**231,660,581**	**257,748,723**	**272,757,460**	**269,443,469**	**286,050,896**
WIP	7,285,640	15,237,370	2,694,853	1,792,056	415,121	315,307	-
TOTAL INCLUDING WIP	**$ 209,967,440**	**$ 210,581,961**	**$ 234,355,434**	**$ 259,540,778**	**$ 273,172,581**	**$ 269,758,777**	**$ 286,050,896**

Detailed Breakdown by Major Plant Account

Paragraph 2.5.1.2 of the Board's Filing Requirements requires that Applicants provide a detailed breakdown by major plant account for each functionalized plant item. For the Test Year, each plant item must be accompanied by a description. In compliance with this requirement, Oakville Hydro has included a breakdown of each major plant account according to the Board's USofA in Table 2-20.

Table 2-20 – Gross Assets Detailed Breakdown by Major Plant Account

Description		2010 Board Approved	2010 Actual	Variance 2010 vs 2010 Board Approved	2011 Actual	Variance 2011 vs 2010 Actual	2012 Actual	Variance 2012 vs 2011	2013 Bridge Old CGAAP	Variance 2013 Bridge vs 2012	2013 Bridge New CGAAP	Variance 2013 New CGAAP vs 2013 Old CGAAP	2014 Test	Variance 2014 Test vs 2013 Bridge MGAAP
REPORTING BASIS		CGAAP	CGAAP		CGAAP		CGAAP		CGAAP		CGAAP		CGAAP	
Land & Buildings														
1805	Land	$ 250,717	$ 300,717	$ 50,000	$ 1,722,054	$ 1,421,336	$ 1,722,054	$ -	$ 1,722,054	$ -	$ 1,722,054	$ -	$ 1,722,054	$ -
1808	Buildings and Fixtures	829,700	829,700	(0)	829,700	-	829,700	-	829,700	-	829,700	-	829,700	-
1810	Leasehold Improvements	2,289,109	2,220,820	(68,289)	3,294,143	1,073,323	3,505,475	211,332	3,577,975	72,500	3,571,521	(6,454)	3,913,136	341,615
	SUBTOTAL LAND & BUILDINGS	**3,369,526**	**3,351,237**	**(18,289)**	**5,845,896**	**2,494,659**	**6,057,228**	**211,332**	**6,129,728**	**72,500**	**6,123,274**	**(6,454)**	**6,464,889**	**341,615**
Distribution Stations														
1815	Transformer Station Equipment	-	-		21,439,242	21,439,242	21,602,201	162,960	21,672,483	70,282	21,663,316	- 9,167	21,663,316	-
1820	Distribution Station Equipment	6,242,086	6,495,990	253,904	6,616,585	120,595	7,310,742	694,157	7,918,899	608,156	7,808,516	- 110,383	8,487,422	678,906
	SUBTOTAL DISTRIBUTION STATIONS	**6,242,086**	**6,495,990**	**253,904**	**28,055,827**	**21,559,837**	**28,912,944**	**857,117**	**29,591,382**	**678,438**	**29,471,832**	**- 119,550**	**30,150,738**	**678,906**
Poles & Wires														
1830	Poles, Towers and Fixtures	29,756,785	15,707,434	(14,049,351)	19,672,787	3,965,353	22,547,385	2,874,598	25,212,322	2,664,937	24,313,064	- 899,258	25,609,254	1,296,190
1835	Overhead Conductors and Devices	11,542,130	26,526,991	14,984,861	29,934,691	3,407,701	31,791,864	1,857,172	33,435,373	1,643,509	32,804,074	- 631,299	33,574,885	770,811
1840	Underground Conduit	58,494,814	53,508,724	- 4,986,090	56,666,855	3,158,132	60,446,766	3,779,911	64,068,567	3,621,801	63,362,180	- 706,387	65,773,948	2,411,768
1845	Underground Conductors and Devices	30,968,943	39,186,068	8,217,125	43,503,361	4,317,293	46,080,876	2,577,515	50,678,225	4,597,350	49,677,590	- 1,000,636	53,229,669	3,552,079
	SUBTOTAL POLES AND WIRES	**130,762,672**	**134,929,216**	**4,166,544**	**149,777,694**	**14,848,478**	**160,866,890**	**11,089,196**	**173,394,487**	**12,527,596**	**170,156,908**	**- 3,237,579**	**178,187,755**	**8,030,847**
Line Transformers														
1850	Line Transformers	42,023,331	41,225,919	(797,412)	42,832,659	1,606,740	44,916,673	2,084,014	47,084,217	2,167,544	46,635,608	(448,609)	53,392,889	6,757,281
	SUBTOTAL TRANSFORMERS	**42,023,331**	**41,225,919**	**(797,412)**	**42,832,659**	**1,606,740**	**44,916,673**	**2,084,014**	**47,084,217**	**2,167,544**	**46,635,608**	**(448,609)**	**53,392,889**	**6,757,281**
Services and Meters														
1855	Services	7,562,222	7,069,750	(492,472)	8,498,135	1,428,385	9,684,898	1,186,763	10,534,440	849,542	10,320,431	(214,009)	10,961,842	641,411
1860	Meters	13,161,792	4,847,078	(8,314,714)	1,412,323	(3,434,755)	1,901,542	489,219	1,901,542	-	1,901,542	-	1,901,542	-
1860	Smart Meters	-	1,223,351	1,223,351	1,362,420	139,070	11,033,523	9,671,103	11,512,725	479,202	11,396,402	(116,323)	11,878,109	481,706
	SUBTOTAL SERVICES AND METERS	**20,724,014**	**13,140,179**	**(7,583,835)**	**11,272,879**	**(1,867,301)**	**22,619,963**	**11,347,084**	**23,948,706**	**1,328,743**	**23,618,375**	**(330,331)**	**24,741,493**	**1,123,118**
IT Assets														
1920	Computer Equipment - Hardware	6,260,452	4,995,556	(1,264,896)	6,625,036	1,629,480	7,174,878	549,842	7,613,378	438,500	7,613,378	-	7,993,378	380,000
1920	Computer Equipment - Hardware - Smart Meters		-	-	-	-	196,133	196,133	196,133	-	196,133	-	196,133	-
1925	Computer Software	3,284,640	4,172,940	888,300	4,172,940	-	5,007,557	834,617	6,094,531	1,086,974	6,070,533	(23,998)	7,301,533	1,231,000
1925	Computer Software - Smart Meters			-		-	279,035	279,035	279,035	-	279,035	-	279,035	-
	SUBTOTAL IT ASSETS	**9,545,092**	**9,168,496**	**(376,596)**	**10,797,975**	**1,629,480**	**12,657,602**	**1,859,627**	**14,183,076**	**1,525,474**	**14,159,079**	**(23,998)**	**15,770,079**	**1,611,000**
Equipment														
1915	Office Furniture and Equipment	848,851	864,156	15,305	870,885	6,729	872,187	1,303	872,187	-	872,187	-	872,187	-
1930	Transportation Equipment	3,736,621	3,436,526	(300,095)	3,899,634	463,107	4,488,353	588,720	5,126,361	638,008	5,071,556	(54,805)	5,456,318	384,762
1935	Stores Equipment	155,867	155,867	0	155,867	-	166,334	10,466	166,334	-	166,334	-	166,334	-
1940	Tools, Shop and Garage Equipment	1,211,917	1,211,150	(767)	1,236,763	25,613	1,279,206	42,443	1,394,645	115,439	1,387,108	(7,537)	1,480,441	93,333
1955	Communication Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	Miscellaneous Equipment	5,200	5,200	0	8,098	2,898	8,098	-	8,098	-	8,098	-	8,098	-
	SUBTOTAL EQUIPMENT	**5,958,456**	**5,672,900**	**(285,556)**	**6,171,247**	**498,346**	**6,814,178**	**642,932**	**7,567,625**	**753,447**	**7,505,283**	**(62,342)**	**7,983,379**	**478,095**
Other Distribution Assets														
1970	Load Management - Customer	171,648	171,648	0	171,648	-	171,648	-	171,648	-	171,648	-	171,648	-
1975	Load Management - Utility	49,876	49,876	(0)	49,876	-	49,876	-	49,876	-	49,876	-	49,876	-
1980	System Supervisory Equipment	4,301,312	3,701,644	(599,668)	3,960,382	258,738	4,486,620	526,238	4,730,620	244,000	4,671,567	(59,052)	4,819,203	147,635
1995	Contributions and Grants- Credit	(33,612,886)	(34,251,899)	(639,013)	(38,964,886)	(4,712,987)	(41,494,285)	(2,529,399)	(45,783,290)	(4,289,005)	(44,809,365)	973,925	(48,108,646)	(3,299,281)
2055	Work In Process	7,285,640	15,237,370	7,951,730	2,694,853	(12,542,517)	1,792,056	(902,798)	415,121	(1,376,935)	315,307	(99,814)	-	(315,307)
	SUBTOTAL OTHER DISTRIBUTION ASSETS	**(21,804,410)**	**(15,091,361)**	**6,713,049**	**(32,088,127)**	**(16,996,766)**	**(34,994,086)**	**(2,905,959)**	**(40,416,025)**	**(5,421,939)**	**(39,600,966)**	**815,059**	**(43,067,919)**	**(3,466,953)**
Other Plant														
2005	Property Under Capital Lease	13,146,673	11,689,385	(1,457,288)	11,689,385	-	11,689,385	-	11,689,385	-	11,689,385	-	12,427,595	738,210
	SUBTOTAL OTHER PLANT	**13,146,673**	**11,689,385**	**(1,457,288)**	**11,689,385**	**-**	**11,689,385**	**-**	**11,689,385**	**-**	**11,689,385**	**-**	**12,427,595**	**738,210**
TOTAL GROSS FIXED ASSETS		**$209,967,440**	**$210,581,961**	**$614,521**	**$234,355,434**	**$23,773,473**	**$259,540,778**	**$25,185,344**	**$273,172,581**	**$13,631,803**	**$269,758,777**	**($3,413,805)**	**$286,050,896**	**$16,292,119**

Summary of Incremental Capital Module Adjustment

In 2011, Oakville Hydro completed the construction of the Glenorchy Municipal Transformer Station (MTS) in order to service the customers of North Oakville. In its 2011 IRM application (EB-2010-0104), Oakville Hydro received approval for the recovery of the incremental capital costs associated with the design and construction of the Glenorchy Municipal Transformer Station. In its Decision and Order, the Board found that the capital costs incurred were prudent and that Oakville Hydro had provided adequate evidence that potential alternatives were analyzed, and that the completion of the project represented the most cost-effective alternative for ratepayers. Oakville Hydro began recovering the revenue requirement associated with Glenorchy Municipal Transformer Station through an Incremental Capital Module ("ICM") Rate Rider which will expire on April 30, 2014. The application was approved at a cost of $21,360,209. Oakville Hydro spent a total of $22,860,578.

A reconciliation of the amount spent versus the Board Approved Amount is provided in Exhibit 2, Tab 5, Schedule 6, under Capital Expenditures.

Reconciliation of Continuity Statements to Calculated Depreciation Expenses

Paragraph 2.5.1.2 of the Filing Requirements requires that the depreciation expense in the fixed asset continuity statements reconcile to the calculated depreciation expenses under Exhibit 4 – Operating Costs and presented by account. In accordance with this requirement there are no reconciling items between the fixed asset continuity statements in this Exhibit and the calculated depreciation expense in Exhibit 4.

Variance Analysis on Gross Assets

The Gross Asset Variance analysis, including Work In Progress (WIP), for the variances highlighted in Table 2-20 is provided as follows.

2010 Board Approved vs. 2010 Actual

The 2010 actual gross assets including WIP were $614,521 higher than the 2010 Board Approved gross assets.

In addition to changes in sustenance capital expenditures, significant decreases were in 1860 - Meters of $7,091,363 and property under capital lease of $1,457,288, offset by increases in WIP of $7,951,730 and Poles and Wires of $4,166,544. These variances are discussed in more detail below.

Meters decreased by $7,091,363, the majority of which was due to the transfer of stranded meters from Account 1860 – Meters to Account 1555 – Sub-account Stranded Meter Costs. Since Oakville Hydro did not complete deployment of Smart Meters until 2011, the Smart Meters were not capitalized until 2012.

The gross asset value of Oakville Hydro's lease at Redwood Square was $11,689,385, which was $1,457,288 lower than the 2010 Board Approved amount. The lease was re-negotiated in 2010 at market rates for a 10 year term. At the time, Oakville Hydro conducted a third-party market review of rates.

The decrease in meters and the capital lease was offset mainly by an increase in WIP of $7,951,730 and Poles and Wires assets of $4,166,544. The increase in WIP was due mainly to the construction of the Glenorchy Municipal Transformer Station in North Oakville which was not in-service until 2011. The 2010 actuals included $11,052,968 in WIP related to the construction of the Glenorchy Transformer Station. The increase in Poles and Wires of $4,166,544 was mainly due to unanticipated increased spending on transformer replacements and voltage conversion (Woodhaven Park), replacing the rear lot distribution system, road-widening projects and underground rebuilds (Poletrans replacements).

For the year 2010, Oakville Hydro re-categorized its fixed assets to better reflect the allocation between USofA accounts. This allocation was based on the results of componentization work which took place as part of the IFRS transition project. As a result there are shifts between the Board's USofA accounts as detailed in Table 2-21.

Table 2-21 - 2010 Gross Fixed Assets Re-Allocation

Description		2010 OEB Filing	Adjustments	2010 Revised
REPORTING BASIS		CGAAP	CGAAP	CGAAP
Land & Buildings				
1805	Land	$300,717		$300,717
1808	Buildings and Fixtures	829,700		829,700
1810	Leasehold Improvements	2,220,820		2,220,820
	SUBTOTAL LAND & BUILDINGS	**$3,351,237**		**$3,351,237**
Distribution Stations				
1815	Transformer Station Equipment			
1820	Distribution Station Equipment	6,495,990		6,495,990
	SUBTOTAL DISTRIBUTION STATIONS	**$6,495,990**		**$6,495,990**
Poles &Wires				
1830	Poles, Towers and Fixtures	30,347,954	(14,640,520)	15,707,434
1835	Overhead Conductors and Devices	11,886,471	14,640,520	26,526,991
1840	Underground Conduit	60,129,698	(6,620,974)	53,508,724
1845	Underground Conductors and Devices	32,565,093	6,620,974	39,186,068
	SUBTOTAL POLES AND WIRES	**$134,929,216**	**($0)**	**$134,929,216**
Line Transformers				
1850	Line Transformers	41,225,919		41,225,919
	SUBTOTAL TRANSFORMERS	**$41,225,919**		**$41,225,919**
Services and Meters				
1855	Services	7,069,750		7,069,750
1860	Meters	4,847,078		4,847,078
1860	Smart Meters			
	SUBTOTAL SERVICES AND METERS	**$13,140,179**		**$13,140,179**
IT Assets				
1920	Computer Equipment - Hardware	6,925,655	(1,930,099)	4,995,556
1920	Computer Equipment - Hardware - Smart Meters			
1925	Computer Software	2,242,840	1,930,099	4,172,940
1925	Computer Software - Smart Meters			
	SUBTOTAL IT ASSETS	**$9,168,496**	**($0)**	**$9,168,496**
Equipment				
1915	Office Furniture and Equipment	864,156		864,156
1930	Transportation Equipment	3,436,526		3,436,526
1935	Stores Equipment	155,867		155,867
1940	Tools, Shop and Garage Equipment	1,211,150		1,211,150
1955	Communication Equipment			
1960	Miscellaneous Equipment	5,200		5,200
	SUBTOTAL EQUIPMENT	**$5,672,900**		**$5,672,900**
Other Distribution Assets				
1970	Load Management - Customer	171,648		171,648
1975	Load Management - Utility	49,876		49,876
1980	System Supervisory Equipment	3,701,644		3,701,644
1995	Contributions and Grants- Credit	(34,251,899)		(34,251,899)
2055	Work In Process	15,237,370		15,237,370
	SUBTOTAL OTHER DISTRIBUTION ASSETS	**($15,091,361)**		**($15,091,361)**
Other Plant				
2005	Property Under Capital Lease	11,689,385		11,689,385
	SUBTOTAL OTHER PLANT	**$11,689,385**		**$11,689,385**
TOTAL GROSS FIXED ASSETS		**$210,581,961**	**($0)**	**$210,581,961**

2010 Actual vs. 2011 Actual

The 2011 actual gross assets, including WIP were $23,773,473 higher than the 2010 gross assets. Table 2-22 summarizes the main drivers behind the increase.

Table 2-22 - 2011 Additions versus 2010

Description	2010 Actual	Glenorchy MTS (1)	Glenorchy Feeders (1)	Glenorchy WIP (1)	Disposals Incl Stranded Meters (2)	Sustenance Capital (3)	2011 Actual	Variance 2011 vs 2010 Actual
REPORTING BASIS	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Land and Buildings	$ 3,351,237	$ 1,421,336				$ 1,073,323	$ 5,845,896	$ 2,494,659
Distribution Stations	6,495,990	21,439,242				120,595	28,055,827	21,559,837
Poles and Wires	134,929,216		3,435,824			11,412,655	149,777,694	14,848,478
Transformers	41,225,919		71,309		(174,016)	1,709,447	42,832,659	1,606,740
Services and Meters	13,140,179				(3,551,434)	1,684,133	11,272,879	(1,867,301)
IT Assets	9,168,496					1,629,480	10,797,975	1,629,480
Equipment	5,672,900		4,229		(5,000)	499,118	6,171,247	498,346
Other Distribution Assets	(15,091,361)		44,409	(11,052,968)		(5,988,207)	(32,088,127)	(16,996,766)
Other Plant	11,689,385					-	11,689,385	-
TOTAL GROSS FIXED ASSETS	**$210,581,961**	**$22,860,578**	**$3,555,771**	**($11,052,968)**	**($3,730,450)**	**$12,140,543**	**$234,355,434**	**$23,773,473**
		$15,363,380	**(1) Glenorchy MTS/Feeders**					

In addition to an increase due to sustenance capital expenditures of $12,140,543 (referenced as (3) in Table 2-22), distribution plant assets increased across several categories to reflect the capitalization of the Glenorchy Municipal Transformer Station and associated feeders. This was partly offset by a reduction in total WIP and meters. These variances are discussed in more detail below.

The Glenorchy Municipal Transformer Station and associated feeders were energized in July 2011 and capitalized for $22,860,578 ($21,439,242 Equipment and $1,421,336 Land) and $3,555,771 respectively. This increase was offset by a decrease in WIP related to the Glenorchy Municipal Transformer Station of $11,052,968 for a net increase of $15,363,380. These changes are referenced as (1) in Table 2-22.

The decrease of $1,867,301 in services and meters is driven by the transfer of the remaining stranded meters to Account 1555 for $3,551,434, referenced as (2) in Table 2-22.

2011 Actual vs. 2012 Actual

The 2012 actual gross assets increased $25,185,354 versus the 2011 gross assets. This increase is a result of sustenance capital expenditures in 2012, the addition of Smart Meters at a cost of $10,118,954 and further expenditures on the Glenorchy Municipal Transformer Station and feeders of $508,273.

2012 Actual vs. 2013 Bridge Year (Old CGAAP)

The increase of $13,631,803 versus 2012 is a result of sustenance capital expenditures during the year, necessary for maintaining the safety and reliability of the distribution system.

2013 Bridge Year (Old CGAAP) vs. 2013 Bridge Year (New CGAAP)

The decrease of $3,413,805 from the 2013 Bridge Year (Old CGAAP) to the 2013 Bridge Year (New CGAAP) represents the impact to gross assets, including WIP, of the change in Oakville Hydro's capitalization policy. Overhead costs previously capitalized under Old CGAAP are expensed under New CGAAP. This decrease of $3,413,805 is comprised of:

- A decrease of $3,313,991 due to the change in capitalization policies on 2013 capital additions in rate base.
- A decrease of $99,814 due to the change in capitalization policies on WIP to be closed in 2014 that is not in rate base. This amount was incurred prior to 2013 and should be captured in account 1576 - Accounting Changes under CGAAP. This treatment is discussed in further detail in Exhibit 2, Tab 6.

The impact of the change in Oakville Hydro's capitalization policy will be offset by the change in its depreciation rates, specifically the average overall increase in useful lives. The impact to depreciation, discussed in Exhibit 4, is a decrease of $3,541,709.

The net impact to Net Book Value of the above changes (the decrease of $3,313,991 in 2013 capital additions, the decrease of $99,814 in WIP and the decrease in accumulated depreciation of $3,541,709 is an increase in Net Book Value including WIP of $127,904 which Oakville

Hydro has captured in account 1576 - Accounting Changes under CGAAP. The changes are summarized in Table 2-23.

Table 2-23 - Impact of Accounting Changes – Net Book Value

Description	2013 Bridge Year - Old CGAAP	2013 Bridge Year - New CGAAP	Variance Old CGAAP vs. New CGAAP
Reporting Basis	CGAAP	CGAAP	
Net Book Value			
Gross Fixed Assets - Rate Base	$ 272,757,460	$ 269,443,469	-$ 3,313,991
Work In Progress	$ 415,121	$ 315,307	-$ 99,814
Gross Fixed Assets - Total	**$ 273,172,581**	**$ 269,758,777**	**-$ 3,413,805**
Accumulated Depreciation	$ 117,923,717	$ 114,382,008	-$ 3,541,709
Total Net Book Value including WIP	**$ 155,248,864**	**$ 155,376,768**	**$ 127,904**

Oakville Hydro's change to depreciation rates and capitalization policy is discussed in further detail in Exhibit 2, Tab 6.

2013 Bridge Year (CGAAP) vs. 2014 Test Year (CGAAP)

Gross Fixed Assets are projected to increase by $16,292,119 versus 2013. This increase is a result of sustenance capital expenditures, including Work in Progress, of $10,553,909, the purchase of an on-site emergency back-up transformer for the Glenorchy Municipal Transformer Station of $5,000,000 and an adjustment in a third party valuation of optical fibres of $738,210.

The on-site emergency back-up transformer project is discussed in more detail in the Distribution System Plan.

The adjustment in the value of a capital lease between Oakville Hydro and a third party for $738,210 is due to the treatment of the contractual agreement for an Indefeasible Right of Use ("IRU") between Oakville Hydro and a third party service provider. The agreement, made on January 4th, 2010, grants Oakville Hydro the right to use fibre optic cables owned by the third party. Oakville Hydro owned the third party and was using fibre optic cables owned and installed by the third party prior to its sale on January 29, 2010. Oakville Hydro continues to use these fibre optic cables in connection with the internal communications of its business including the communication of electricity consumption information, and for Supervisory Control and Data Acquisition ("SCADA") purposes. Under CGAAP, the IRU is considered a capital lease. Since the agreement was effective January 4, 2010 which was prior to the sale of the third party, the agreement was between two related parties, and as such, the IRU was required to be recorded at net book value. However, for the purposes of the Oakville Hydro's Cost of Service Application, the IRU should be included in rate base at market value, as determined by the parties during the Settlement Agreement for Oakville Hydro's 2010 Cost of Service application on April 26, 2010.

In the Settlement Agreement, the parties agreed that recording the fibre optic cables at Net Book Value may not reflect the appropriate approach for rate making purposes and agreed that Oakville Hydro may, in a subsequent cost of service proceeding, provide independent evidence of a more appropriate value. Consequently, Oakville Hydro engaged an independent third party to prepare a valuation of the fibre optic network. Oakville Hydro obtained an independent third party assessment of the market value of the fibre optic network of $894,800, filed as Appendix C of this Exhibit. The addition of the third party IRU of $738,210 in the 2014 capital additions represents the difference between the depreciated market value and the depreciated book value of the lease of the fiber optic network as at December 31, 2013. Its depreciated value of $693,470 as at December 31, 2014 has been added to the 2014 Test Year rate base.

Allowance for Working Capital

Overview and Calculation by Account

The Filing Requirements permit applicants to take one of two approaches for the calculation of the allowance for working capital; the 13% Allowance Approach or the filing of a lead/lag study. Using the 13% Allowance Approach, the working capital allowance is calculated to be 13% of the sum of Cost of Power and controllable expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

Oakville Hydro did not conduct a lead lag study and it is using the 13% Allowance Approach in accordance with the Filing Requirements as Oakville Hydro has not received previous direction from the Board. The working capital allowance for the 2014 Test Year is based upon 13% of the Cost of Power and controllable expenses. In calculating the working capital allowance for 2010 to 2012 actual and for the 2013 Bridge Year, are based on the Board's historical 15% Allowance Approach.

Table 2-24 provides a summary of Oakville Hydro's cost of power and controllable expenses used to calculate working capital for the years 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, the 2013 Bridge and the 2014 Test Year.

Table 2-24 - Working Capital Allowance Calculation

Description	2010 OEB Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Cost of Power (COP)	$ 119,838,040	$ 130,384,214	$ 138,129,434	$ 149,133,411	$ 160,514,381	$ 159,625,872
Controllable Expense:						
Operations	4,060,217	3,645,295	4,953,375	4,755,638	7,837,739	8,103,561
Maintenance	2,074,335	1,922,776	1,982,894	2,552,677	2,556,425	2,654,124
Billing & Collecting	1,252,147	1,463,012	1,334,858	2,021,868	1,822,117	2,443,644
Community Relations	89,686	99,489	117,528	215,373	149,669	269,832
Administration & General Expense	4,152,419	3,887,171	4,744,456	4,461,324	5,558,455	5,743,840
Property Taxes	210,600	184,443	181,762	170,969	199,200	203,184
Total Controllable Expense	11,839,403	11,202,186	13,314,873	14,177,849	18,123,605	19,418,184
Total Controllable Expense & COP	**131,677,443**	**141,586,399**	**151,444,308**	**163,311,261**	**178,637,985**	**179,044,057**
Working Capital Allowance Rates	15%	15%	15%	15%	15%	13%
Working Capital Allowance	**$ 19,751,616**	**$ 21,237,960**	**$ 22,716,646**	**$ 24,496,689**	**$ 26,795,698**	**$ 23,275,727**

As shown in Table 2-25, the 2014 working capital allowance has increased $3,524,111 or 17.8% in comparison to the 2010 Board Approved Year. The change between the 2014 Test Year and 2010 Board Approved Year is a result of increased working capital requirements due to increased costs of power and increased controllable expenses, the change to capitalization policies, less the decrease in percentage rate applied in the computation of the working capital allowance from 15% to 13%. Detailed cost of power calculations are provided in Schedule 1, Tab 3 of this Exhibit.

Table 2-25– Summary of Changes in Working Capital Allowance

Description	2010 OEB Approved	2014 Test Year	Change	Working Capital Allowance Factor	Working Capital Allowance
Cost of Power (COP)	$ 119,838,040	$ 159,625,872	$ 39,787,832	15%	$ 5,968,175
Controllable Expenses	11,839,403	19,418,184	7,578,781	15%	1,136,817
Total	**$ 131,677,443**	**$ 179,044,057**	**$ 47,366,614**		**$ 7,104,992**
Controllable Expenses & COP		179,044,057		13%	23,275,727
		179,044,057		15%	26,856,609
Decrease in Working Capital Allowance					**- 3,580,881**
Net Working Capital Allowance Impact					**3,524,111**

Cost of Power Calculation

Oakville Hydro's has calculated the Cost of Power for the 2014 Test Year based upon the 2014 load forecast, adjusted for the impact of Conservation and Demand Management ("CDM") activities, and its proposed loss factor of 1.0372. Oakville Hydro's market participant customer has been excluded from the calculation of Electricity and Regulatory costs but is included in the calculation of the retail transmission costs. Detailed calculations are provided in Table 2-27, 2014 Cost of Power Calculation.

Commodity Prices

In accordance with the Filing Requirements, the commodity price estimate used to calculate the Cost of Power was determined in a way that bases the split between Regulated Price Plan ("RPP") and non-RPP customers on actual data and uses the most current RPP price. The most current non-RPP price was obtained from Ontario Wholesale Electricity Market Price Forecast Report for the period May 1, 2013 through October 31, 2014 prepared by Navigant Consulting and presented to the Board on March 28, 2013. Oakville Hydro understands that the commodity charge will be updated to reflect any changes to commodity prices that may become available prior to the approval of its Application.

Non-RPP Pricing

In its report, Navigant estimated that the average Hourly Ontario Energy Price ("HOEP") for the period from May 2013 to April 2014 would be $0.01933 per kWh and the HOEP for the period May 2014 to October 2014 would be $0.01533 per kWh. Oakville Hydro has the HOEP based on the weighted average HOEP provided by Navigant from January to October 2014 and the assumption that the HOEP in November and December of 2014 will remain at the same level as October 2014. As shown in Table 2-26, the average HOEP price of $0.01647 per kWh was used as the basis for the 2014 cost of power estimate. Oakville Hydro will update the forecasted HOEP for 2014 once additional information is available. The Global Adjustment is calculated using the forecasted rate of $0.06612 per kWh as provided in the Board's Regulated Price Plan Report (the "RPP Report").

Table 2-26, Weighted Average HOEP for Non-RPP Consumers

Month	HOEP ($ per MWh)
January	23.11
February	17.48
March	17.48
April	17.48
May	15.07
June	15.07
July	15.07
August	15.38
September	15.38
October	15.38
November	15.38
December	15.38
Average	**16.47**

RPP Pricing

In its RPP Report, the Board estimated the RPP price for the period from May 1, 2013 through April 30, 2014 to be $0.08395 per kWh. Oakville Hydro has used the estimate of $0.08395 per kWh for the 2014 Test Year for Residential and General Service < 50 KW customers who are on RPP pricing. Oakville Hydro will update the RPP price once additional information is available.

Uniform Transmission Rates

Oakville Hydro has calculated Retail Transmission charges using the most recent Uniform Transmission Rates ("UTR") approved by the Board (EB-2012-0031), issued on December 20, 2012 and effective January 1, 2013.

- Network Service Rate: $3.57 per kW
- Line Connection Service Rate: $0.08 per kW
- Transformation Connection Service Rate: $1.86 per kW

Oakville Hydro understands the transmission charges will be updated to reflect any new rates that may become available prior to the approval of its Application.

Regulatory Charges

The Wholesale Market Service ("WMS") costs are calculated based on the current rates and forecasted purchases for the 2014 Test Year. The current rate for WMS and the Rural Rate Assistance ("RRA") are $0.0044 per kWh and $0.0012 respectively.

Smart Meter Entity Charge

The Smart Meter Entity costs are calculated based on the rate of $0.788 per month for each Residential and General Service < 50 kW customer approved by the Board on March 28, 2013.

2014 Cost of Power Calculation

Oakville Hydro has calculated the cost of power for the 2014 Test Year as $159,110,509. Table 2-27, 2014 Cost of Power Calculation provides the detailed calculation of the cost of power for the 2014 Test Year.

Table 2-27, 2014 Cost of Power Calculation

Forecasted Purchases	Residential	General Service < 50 kW	Unmetered	General Service > 50 kW	General Service > 1,000 kW	Embedded Distributor	Sentinel Lighting	Street Lighting	Total
Average Number of Customers	59,243	4,923							
Non-RPP Forecast (kWh)	30,723,902	25,813,211	25,991	539,610,046	152,869,265	31,839,095	-	9,275,778	790,157,289
RPP Forecast (kWh)	586,875,919	138,591,589	3,608,378	85,111,792	-	-	121,132	-	814,308,810
Total kWh	617,599,821	164,404,801	3,634,370	624,721,838	152,869,265	31,839,095	121,132	9,275,778	1,604,466,099
Commodity Charges									
Non-RPP Coommodity Charge ($0.08259/kWh)	$ 2,537,487	$ 2,131,913	$ 2,147	$ 44,566,394	$ 12,625,473	$ 2,629,591	$ -	$ 766,087	$ 65,259,090
RPP Commodity Charge($0.08395/kWh)	$ 49,268,233	$ 11,634,764	$ 302,923	$ 7,145,135	$ -	$ -	$10,169	$ -	$ 68,361,225
Total Commodity Charges	**$ 51,805,720**	**$ 13,766,677**	**$ 305,070**	**$ 51,711,529**	**$ 12,625,473**	**$ 2,629,591**	**$10,169**	**$ 766,087**	**$ 133,620,315**
Retail Transmission Charges									
Forecasted Billing Determinants (kW/kWh)	617,599,821	164,404,801	3,634,370	1,589,641	329,822	73,000	324	24,961	
Transmission Network Rate	$ 0.0072	$ 0.0067	$ 0.0067	$ 2.4866	$ 2.5669	$ 2.5669	$0.4984	$ 2.0744	
Transmission Network Charges	**$4,446,718.71**	**$ 1,101,512.16**	**$24,350.28**	**$ 3,952,802.03**	**$ 846,619.70**	**$187,383.70**	**$161.69**	**$51,778.11**	**$ 10,611,326**
Transmission Connection Rate	$ 0.0036	$ 0.0033	$ 0.0033	$ 1.2375	$ 1.2776	$ 1.2776	$0.2480	$ 1.0324	
Transmission Connection Charges	**$ 2,223,359**	**$ 542,536**	**$ 11,993**	**$ 1,967,181**	**$ 421,380**	**$ 93,265**	**$ 80**	**$ 25,769**	**$ 5,285,565**
Regulatory Charges									
Wholesale Market Service Rate	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$ 0.0044	$0.0044	$ 0.0044	
Rural Rate Protection Rate	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$ 0.0012	$0.0012	$ 0.0012	
Regulator Charges	**$ 3,458,559**	**$ 920,667**	**$ 20,352**	**$ 3,498,442**	**$ 856,068**	**$ 178,299**	**$ 678**	**$ 51,944**	**$ 8,985,010**
Smart Metering Charge									
Monthly Smart Metering Rate per Customer	$ 0.79	$ 0.79	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Metering Charge	**$ 561,628**	**$ 46,666**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 608,293**
Total Cost of Power	**$ 62,495,985**	**$ 16,378,058**	**$ 361,766**	**$ 61,129,954**	**$ 14,749,541**	**$ 3,088,538**	**$11,090**	**$ 895,578**	**$ 159,110,509**

Treatment of Stranded Assets Related to Smart Meter Deployment

Oakville Hydro is seeking disposition of the net book value of its stranded meters as at April 30, 2014. In accordance with the OEB's *Guideline G-2011-0001 Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001"), whereby distributors are to be "held whole with respect to the cost recovery of stranded meters (i.e. conventional meters replaced as part of the smart meter initiative)"[1], Oakville Hydro seeks disposition of its stranded meter costs as at April 30th, 2014 in the amount of $3,331,805. This represents the amount of the pooled residual net book value of the meters removed from service, less any net proceeds from sales of the meters and contributed capital attributable to the meters at April 30, 2014.

In accordance with the Board's *Guideline G-2008-0002, Smart Meter Funding and Cost Recovery*, Oakville Hydro transferred the cost of stranded meters from Account 1860 - Meters to Account 1555 - Sub-account Stranded Meter Costs.

The amount recorded in Account 1555 is based on the number of meters removed during each year as a result of the deployment of smart meters multiplied by the average installation cost of each type of meter to calculate gross asset value. Installation costs for each type of meter is included in the cost of the meter as well as the costs of other material, labour, vehicles, and associated burdens. Labour and vehicles were calculated based on the installation time per meter at the corresponding hourly labour rate. Associated accumulated amortization was calculated factoring in the year of installation, the year of removal and a 25 year useful life to April 30, 2014.

On April 3, 2012, Oakville Hydro filed an application for the disposition and recovery of costs related to smart meter deployment (the "Smart Meter Application"). In its Smart

[1] *OEB G-2011-000 Guideline Smart Meter Funding and Cost Recovery – Final Disposition*, dated December 15, 2011 p. 21.

Meter Application, Oakville Hydro proposed to dispose of its stranded meters in its next cost of service application. In response to Board staff Interrogatory number two, Oakville Hydro stated that it expected that the net book value of its stranded meters was $6,145,304 and that it would remain unchanged through December 31, 2013. In its submission, Board staff stated that Oakville Hydro should continue to depreciate the net book value of the stranded meters until its next cost of service application as per Guideline G-2011-0001. In accordance with Guideline G-2011-0001, Oakville Hydro has recorded depreciation to April 30, 2014 as reflected in the net book value of $3,331,805 requested for disposition.

In 2006, developers were being charged for the costs of meters installed beyond the transformer in residential subdivisions. These meters were removed and replaced by Smart Meters. Therefore, Oakville Hydro has subtracted the depreciated value of the contributed capital from the net book value of the stranded meters.

The amount of stranded meters requested for disposition at April 30, 2014 is forecasted to be $3,331,805. In accordance with the Accounting Procedures Handbook, no carrying charges were recorded for the stranded meter cost balances in the sub-account of Account 1555. A reconciliation of the amount requested for disposition is provided in Table 2-28.

Table 2-28, Reconciliation of Stranded Meter Net Book Value

Description	Amount
Net Book Value of Stranded Meters as per Smart Meter Application	$6,145,034
Depreciation to April 30, 2014 as per Guideline G-2011-0001	(1,095,828)
Depreciated Value of Contributed Capital	(1,717,401)
Net Book Value of Stranded Meters as at April 30, 2014	**$3,331,805**

Board Appendix 2-S, Stranded Meter Treatment provides the net book value of the stranded meters, reflecting contributed capital, accumulated depreciation to April 30, 2014 and the proceeds of disposition on the sale of the stranded meters.

Appendix 2-S
Stranded Meter Treatment

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2010	Actual	$ 7,878,148	$ 2,538,843	$ -	$ 5,339,305	$ 64,391	$ 5,274,913
2011	Actual	$ 9,103,988	$ 2,884,320	$ -	$ 6,219,668	$ 74,635	$ 6,145,034
2012	Actual	$ 9,222,024	$ 3,375,922	$ 1,842,347	$ 4,003,755	$ 74,635	$ 3,929,120
2013	Fcst	$ 9,222,024	$ 3,976,798	$ 1,748,637	$ 3,496,590	$ 74,635	$ 3,421,955
2014	Fcst	$ 9,222,024	$ 4,098,185	$ 1,717,400	$ 3,406,440	$ 74,635	$ 3,331,805

Stranded Meter Values by Rate Class

The number of stranded meters and the net book value those meters stranded by rate class is summarized in Table 2-29**.** The net book value of the stranded meters by rate class was determined based upon the type of meter that was installed for the Residential and General Service < 50 kW customers as recorded in Oakville Hydro's Customer Information System. Unit cost for each type of meter included the cost of the meter and other material if applicable, labour, vehicles, and associated overhead costs. Labour and vehicle costs were calculated as the installation time per meter at the corresponding hourly labour rate.

Table 2-29: Stranded Meter Values by Rate Class

Rate Class	# of Meters	Average Unit Cost	Gross Cost	Accum Deprn	Contr Cap	Proceeds	Net Book Value
Residential	54,147	$143	$7,762,649	($3,284,467)	($1,717,400)	($74,635)	$2,686,148
GS <50kW	4,988	$293	$1,459,375	($813,718)	$0	$0	$645,657
TOTAL	**59,135**		$9,222,024	($4,098,185)	($1,717,400)	($74,635)	$3,331,805

Oakville Hydro is requesting the recovery of the Net Book Value of the stranded meters of $3,331,805 as at April 30, 2014 through separate Stranded Meter Rate Riders for each the Residential and General Service < 50 kW rate classes over a five-year period. Recovery of the net book value of the stranded meters over a five-year period aligns with Oakville Hydro's next scheduled cost of service application in 2019 and minimizes the bill impact for the Residential and General Service < 50 kW customers.

Oakville Hydro proposes to recover the net book value of the stranded meters through a fixed monthly Stranded Meter Rate Rider for the Residential and General Service < 50kW rate classes. The proposed disposition is calculated based upon the net book value of stranded meters by rate class and the forecast of the average number of customers in the 2014 Test Year.

Based on Oakville Hydro's 2014 forecast of the average number of customers for the 2014 Test Year, Oakville Hydro requests approval for a Stranded Meter Rate Rider $0.76 per month for each Residential customer and $2.19 per month for each metered customer in the General Service < 50 kW rate class. Table 2-30, Stranded Meter Rate Rider, summarizes the calculation of the proposed Stranded Meter Rate Rider.

Table 2-30: Stranded Meter Rate Rider

Rate Class	Total Stranded Meter Recovery	Recovery Period	Annual Stranded Meter Recovery	Average # of Customers	Proposed Rate Rider
Residental	$2,686,148	5	$537,230	59,243	$0.76
GS <50kW	$645,657	5	$129,131	4,923	$2.19
TOTAL	**$3,331,805**		**$666,361**		

Capital Expenditures

Planning

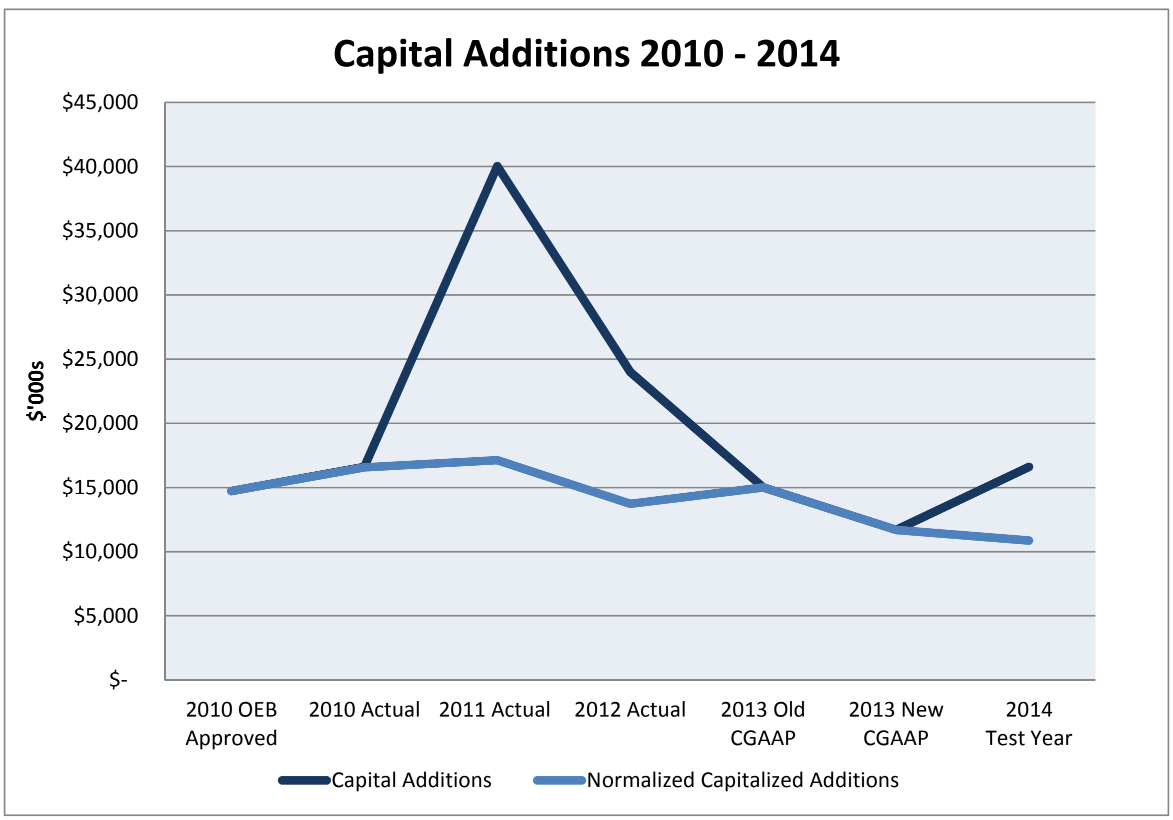
In accordance with the Filing Requirements, Oakville Hydro is filing its consolidated Distribution System Plan ("DS Plan") as a stand-alone document which includes all elements of the DS Plan as Appendix A of this Exhibit. Oakville Hydro has organized its information using the headings indicated in Chapter Five of *the Board's Filing Requirements for Electricity Distribution and Transmission Applications*, entitled *Consolidated Distribution System Plan Filing Requirements* (the "DS Plan Filing Requirements").

Capital Expenditures - Required Information

Overall Summary of Capital Expenditures

Oakville Hydro has filed the Capital Expenditure Summary from Chapter 5 Consolidated DS Plan Filing Requirements on the following page. Explanatory notes on variances are included in the consolidated DS Plan.

Oakville Hydro's capital additions in 2014 are expected to be $16,607,427. Once the impact of the Smart Meter Initiative and the Glenorchy Municipal Transformer Station have been removed from the historical additions, capital additions are fairly consistent year over year, with the exception of 2012 to 2013, due to a reduction of $3,313,991 in burdens under Oakville Hydro's revised capitalization policy effective January 1, 2013. Oakville Hydro's change to capitalization policy is discussed in further detail in Exhibit 2, Tab 6.



Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2014*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access		5,782	--		3,307	--		29,215	--		3,090	--	3,291	3,822	16.1%	2,322	2,130	2,448	2,497	2,639
System Renewal		13,001	--		11,146	--		6,939	--		7,571	--	5,573	5,535	-0.7%	5,980	5,436	5,505	5,599	5,599
System Service		1,449	--		916	--		838	--		11,351	--	79	201	155.0%	5,589	559	581	605	629
General Plant		2,535	--		1,247	--		3,055	--		1,984	--	2,549	2,137	-16.2%	2,717	2,126	2,866	2,052	2,063
TOTAL EXPENDITURE	18,232	22,767	24.9%	14,721	16,615	12.9%	29,024	40,046	38.0%	13,562	23,996	76.9%	11,493	11,695	1.8%	16,607	10,251	11,401	10,752	10,931
System O&M	n/a	$ 5,852	--		$ 6,135	--	n/a	$ 6,936	--	n/a	$ 7,308	--	$ 10,140	$ 10,394	2.5%	$10,526	n/a	n/a	n/a	n/a

NORMALIZED CAPITAL EXPENDITURES (EXCLUDING GLENORCHY MTS, SMART METERS, 3rd PARTY IRU)

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access	-	4,967	--	2,372	3,307	39.4%	-	6,354	--	-	2,931	--	3,291	3,822	16.1%	2,322	2,130	2,448	2,497	2,639
System Renewal	-	13,001	--	8,662	11,146	28.7%	-	6,939	--	-	7,571	--	5,573	5,535	-0.7%	5,980	5,436	5,505	5,599	5,599
System Service	-	1,449	--	781	916	17.2%	-	783	--	-	1,232	--	79	201	155.0%	589	559	581	605	629
General Plant	-	1,635	--	2,906	1,247	-57.1%	-	3,055	--	-	1,984	--	2,549	2,137	-16.2%	1,979	2,126	2,380	2,052	2,063
TOTAL NORMALIZED EXPENDITURE	18,232	21,052	15.5%	14,721	16,615	12.9%	17,938	17,132	-4.5%	13,562	13,718	1.1%	11,493	11,695	1.8%	10,869	10,251	10,915	10,752	10,931
Glenorchy MTS/Emergency Back-up Transformer	-	-		-	-		9,186	22,861		-	159		-	-		5,000	-	-	-	-
Smart Meters	-	-		-	-		1,900	54		-	10,119		-	-		-	-	-	-	-
New Customer Information System	-	-		-	-		-	-		-	-		-	-		-	-	486	-	-
CDM Activities	-	1,715		-	-		-	-		-	-		-	-		-	-	-	-	-
3rd Party IRU	-	-		-	-		-	-		-	-		-	-		738	-	-	-	-
TOTAL EXPENDITURE	18,232	22,767	24.9%	14,721	16,615	12.9%	29,024	40,046	38.0%	13,562	23,996	76.9%	11,493	11,695	1.8%	16,607	10,251	11,401	10,752	10,931

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): 5

Capital Additions by Year and by Project

The following tables and written explanations summarize Oakville Hydro's actual capital additions for the historical years 2010, 2011, and 2012 and the estimated capital additions for the 2013 Bridge Year and 2014 Test Year. Table 2-31 summarizes Oakville Hydro's spending by year. A summary of Oakville Hydro's capital projects by year is provided in the Capital Projects Table, Board Appendix 2-AA.

Table 2-31 – 2008 to 2014 Capital Projects

Description	2008	2009	2010 OEB Approved	2010	2011	2012	2013 Bridge Year Old CGAAP	2013 Bridge Year New CGAAP	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
System Access	$4,318,440	$4,966,760	$2,372,414	$3,256,569	$6,354,058	$2,930,624	$5,314,658	$3,821,848	$2,321,862
System Renewal	8,576,666	13,001,085	8,661,580	11,145,948	6,938,864	7,571,478	7,234,446	5,534,829	5,979,745
System Service	143,476	1,449,334	781,224	915,736	783,272	1,231,890	230,214	201,443	588,899
General Plant	2,292,393	1,634,889	2,906,009	1,247,058	3,055,398	1,984,179	2,229,421	2,136,627	1,978,710
Total Ex MTS/Smart Meters	**$15,330,975**	**$21,052,068**	**$14,721,227**	**$16,565,311**	**$17,131,592**	**$13,718,170**	**$15,008,738**	**$11,694,747**	**$10,869,217**
Glenorchy MTS/Emergency Back-up Transformer				50,000	22,860,578	159,348			5,000,000
Smart Meters					54,271	10,118,954			
Remaining 3rd Tranche CDM Activities		1,715,132							
3rd Party IRU									738,210
Grand Total	**$15,330,975**	**$22,767,200**	**$14,721,227**	**$16,615,311**	**$40,046,440**	**$23,996,472**	**$15,008,738**	**$11,694,747**	**$16,607,427**

Appendix 2-AA
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
System Access	**4,139,081**	**5,746,031**	**3,306,569**	**29,059,361**	**2,978,136**	**3,793,912**	**2,197,868**
27.6 kV Additions							
27.6kV Additions TBD	0	0	0	0	0	0	420,973
Additional CCT	394,758	524,026	418,821	0	0	0	0
Glenorchy Feeders	0	0	0	3,555,771	348,925	0	0
Glenorchy North Oakville TS	0	0	50,000	22,860,578	159,348	61,115	0
Hospital Feeder Construction	0	0	0	0	0	807,547	0
Milton Feeder Construction from Glenorchy	0	0	0	0	0	464,620	0
Winston Churchill Blvd.	0	290,464	12,075	0	213,732	0	0
Sub-Total	**394,758**	**814,489**	**480,896**	**26,416,349**	**722,005**	**1,333,282**	**420,973**
Meters							
Multi-Residential to Individual Metering	0	815,150	378,596	0	0	0	0
Distribution Meters	528,632	771,085	235,431	213,136	673,701	362,879	481,706
Wholesale Metering	0	0	257,900	0	0	0	0
Sub-Total	**528,632**	**1,586,235**	**871,927**	**213,136**	**673,701**	**362,879**	**481,706**
New Development and Services							
Sub-Total	**2,800,568**	**2,924,906**	**1,346,001**	**1,558,676**	**1,043,129**	**1,102,130**	**1,016,068**
Road Widening - no OH Control							
Bronte Rd/QEW Relocations	51,272	266,413	0	9,965	0	0	0
Dundas St Widening, Old Bronte Rd. to Proudfoot Trail	0	0	0	0	0	455,300	0
Dundas St Widening, Stages 2 & 3	0	0	0	314,089	247,424	2,002	0
Neyagawa Rd Widening, Dundas St. to Burnhamthorpe Rd	0	0	0	0	0	538,319	0
Rebuild for Road Widening - Miscellaneous	138,260	135,840	607,745	547,146	3,039	0	279,121
Region Bridge Construction - Dundas/16 Mile	225,590	18,148	0	0	0	0	0
Road Widening - 9th Line	0	0	0	0	288,837	0	0
Sub-Total	**415,122**	**420,401**	**607,745**	**871,200**	**539,300**	**995,621**	**279,121**
System Renewal	**8,001,659**	**12,528,628**	**10,672,496**	**6,303,077**	**7,277,448**	**4,875,941**	**4,713,776**
Load Transfer and System Security							
27.6Kv Air Insulated Switchgear Upgrade	0	0	0	0	280,842	323,671	379,340
Transformer Top Replacements	240,458	96,058	225,268	95,973	155,797	0	0
Gang-Operated Switch Replacement	0	0	0	0	0	0	267,139
Underslung Switch Replacement	0	0	0	0	417,440	-52,313	66,974
Sub-Total	**240,458**	**96,058**	**225,268**	**95,973**	**854,080**	**271,358**	**713,452**
O/H Rebuilds							
600 Amp, 13.8kV Switch Replacement	0	0	36,944	183,206	0	0	0
Concrete Poles	0	0	0	617,409	42,664	0	0
Pole Replacements	1,083,322	1,544,348	824,830	767,177	387,696	117,422	68,744
Rebuild 4.16kV System	0	0	610,751	468,900	0	0	0
Rebuild 4kV System	547,480	2,461,988	1,531,971	382,340	485,531	0	0
Rebuild Overhead Distribution System - Various Area	1,290,315	10,647	343,561	338,682	255,135	151,977	566,189
Reinsulation	422,727	523,814	469,501	302,568	0	0	0
Replace O/H Assets on Robinson Street	0	0	0	0	0	0	458,981
Replace/Rebuild Rear Lot Distribution	1,243,098	3,275,048	1,086,708	498,909	1,276,059	1,558,346	0
Sub-Total	**4,586,943**	**7,815,845**	**4,904,266**	**3,559,192**	**2,447,085**	**1,827,745**	**1,093,914**
Substations							
Arkendo MS - Construct New Substation	0	2,010,806	628	0	0	0	0
Margaret MS - Replace Transformer	0	278,445	0	0	0	0	0
MS Low Voltage Breaker Replacement Program	0	0	0	0	0	287,126	547,715
Munns MS Breaker and Switchgear Replacement	0	0	0	0	591,398	-5,876	0
Power Transformer Replacement Program	0	0	0	0	0	257,334	268,190
Substation Air Breaker Retrofits	0	0	407,411	0	0	0	0
Substation Equipment Refurbishment/Upgrades	243,825	69,349	212,387	172,254	52,220	165,931	114,073
Substation Oil Breaker Retrofits	0	679,383	352,639	0	0	0	0
Sunset MS - Replace Transformer	0	0	0	304,713	0	0	0
Sub-Total	**243,825**	**3,037,983**	**973,067**	**476,967**	**643,618**	**704,515**	**929,978**
Supervisory							
Replace/Upgrade Line Switch RTUs	110,587	163,002	191,482	117,629	269,235	105,869	105,815
Sub-Total	**110,587**	**163,002**	**191,482**	**117,629**	**269,235**	**105,869**	**105,815**

Appendix 2-AA
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Transformer Replacements and Voltage Conversion							
Allan MS - Eliminate Station	0	0	0	237,298	22,442	105,132	0
Delta Transformer Replacements	0	0	0	0	197,865	96,304	172,171
Howard Ave / Park Ave	0	0	238,587	0	0	0	0
Live Front Padmount Transformer Replacements	0	0	0	0	0	0	275,730
South of Lakeshore Rd	818,885	0	0	0	0	0	0
Unallocated Transformers (Spare)	-47,415	-150,862	598,177	0	277,018	0	0
Underground/Overhead Transformers	246,942	226,555	334,898	80,602	476,538	136,759	118,430
Woodhaven Park Area Rearlot Zone 2	0	0	424,435	0	0	0	0
Sub-Total	**1,018,411**	**75,693**	**1,596,097**	**317,900**	**973,862**	**338,196**	**566,332**
Rebuild Underground Distribution System							
Holten Heights Area Secondary Rebuild	0	0	0	562,928	944,742	626,940	0
McCraney Area - Primary Rebuild	0	0	470,370	0	0	0	0
Rebuild Underground Distribution System - Misc	309,734	382,302	127,782	835	184,431	3,764	0
Replace Poletrans	814,758	0	1,241,094	122,336	738,691	438,689	292,164
Replace U/G Assets on Colchester, Oakhill, Dolphin and Albion	0	0	0	0	0	0	385,205
Replace U/G Assets on Speers Rd (Kerr to Cross)	0	0	0	0	0	411,117	0
Replace U/G Assets on Willowbrook Dr and Wendy Ln	0	0	0	0	0	0	184,665
Retrofit PMH Switchgear	382,286	438,621	844,647	548,250	31,678	0	0
Splice Replacement Program	0	249,901	0	0	0	0	0
Spring Garden Drive Primary Rebuild	0	0	0	203,417	0	0	0
Switchgear Refurbishment Program	294,656	269,222	98,424	0	0	0	0
Transformer Bushing Insert/Elbow Replacements	0	0	0	297,650	190,027	147,747	126,011
Vault Transformer Removals	0	0	0	0	0	0	316,241
Sub-Total	**1,801,434**	**1,340,046**	**2,782,317**	**1,735,416**	**2,089,569**	**1,628,257**	**1,304,285**
System Service	**41,151**	**1,214,229**	**670,956**	**791,555**	**11,217,808**	**40,000**	**5,300,000**
27.6kV Additions							
Remote Controlled Switch Installations	39,176	91,298	265,218	576,784	322,926	0	0
Switching Improvements - Winston Park	1,976	0	405,739	24,576	0	0	0
Sub-Total	**41,151**	**91,298**	**670,956**	**601,360**	**322,926**	**0**	**0**
IT Capital							
Field Communications	0	0	0	135,924	190,630	0	0
SCADA and OMS	0	815,417	0	0	585,298	40,000	300,000
Sub-Total	**0**	**815,417**	**0**	**135,924**	**775,928**	**40,000**	**300,000**
AMI - Smart Metering Rollout							
Sub-Total	**0**	**0**	**0**	**54,271**	**10,118,954**	**0**	**0**
Substations							
Spare Substation Transformer	0	307,514	0	0	0	0	0
Sub-Total	**0**	**307,514**	**0**	**0**	**0**	**0**	**0**
Emergency Back-up Transformer for Glenorchy MTS							
Sub-Total	**0**	**0**	**0**	**0**	**0**	**0**	**5,000,000**
General Plant	**1,573,504**	**1,724,946**	**903,344**	**2,734,558**	**1,549,972**	**1,906,172**	**2,106,734**
Administration - IT							
Asset Management	0	0	0	0	262,610	110,000	100,000
Blink IRU	0	0	0	0	0	0	738,210
Customer Service	76,539	8,761	0	0	67,014	110,000	210,000
ERP	745,265	124,110	149,382	194,074	78,195	342,500	203,000
GIS	70,927	0	126,728	728,642	188,862	260,858	150,000
Infrastructure	149,185	254,878	554,294	382,619	215,256	515,549	420,000
Organizational Effectiveness	0	0	0	188,220	0	40,570	76,000
Sub-Total	**1,041,915**	**387,749**	**830,404**	**1,493,556**	**811,937**	**1,379,477**	**1,897,210**

Appendix 2-AA
Capital Projects Table

Projects	2008	2009	2010	2011	2012	2013 Bridge Year	2014 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Administration - Building							
HVAC Replacement	0	0	72,940	92,180	0	0	209,524
Peak Demand Reduction	0	899,982	0	0	0	0	0
Re-Roofing, renovations and furniture	0	0	0	851,368	0	0	0
Sub-Total	**0**	**899,982**	**72,940**	**943,548**	**0**	**0**	**209,524**
Vehicles							
Replace 38ft Single Bucket Hybrid	0	0	0	0	0	187,648	0
Replace Derrick Digger(s)	370,619	0	0	297,454	0	0	0
Replace Double Bucket Truck (s)	0	437,215	0	0	449,337	0	0
Replace Single Bucket Truck (s)	160,970	0	0	0	288,697	0	0
Hybrid Aerial Device	0	0	0	0	0	339,048	0
Sub-Total	**531,589**	**437,215**	**0**	**297,454**	**738,034**	**526,695**	**0**
Miscellaneous	1,575,580	1,553,366	1,061,946	1,157,890	973,109	1,078,722	2,289,049
Total	**15,330,975**	**22,767,200**	**16,615,311**	**40,046,440**	**23,996,472**	**11,694,747**	**16,607,427**
Less Renewable Generation Facility Assets and Other Non Rate-Regulated Utility Assets *(input as negative)*							
Total	**15,330,975**	**22,767,200**	**16,615,311**	**40,046,440**	**23,996,472**	**11,694,747**	**16,607,427**

Variance Analysis

Table 2-32 summarizes Oakville Hydro's capital additions by major project by year. A written explanation of variances, including that of actuals versus Board-approved amounts for Oakville Hydro's last Board-approved cost of service is included below.

Table 2-32: Capital Additions by Major Project by Year

Major Project	2010 Board-Approved	2010 Actuals	2011 Actuals	2012 Actuals	2013 Bridge Year Old CGAAP	2013 Bridge Year New CGAAP	2014 Test Year New CGAAP
27.6kV Additions	$400,000	$480,896	$26,416,349	$722,005	$1,879,441	$1,333,282	$420,973
Distribution Meters / Wholesale Meter Upgrades	732,398	871,927	213,136	673,701	479,202	362,879	481,706
New Development / Services	1,075,016	1,346,001	1,558,676	1,043,129	1,412,561	1,102,130	1,016,068
Road Widening (Dependent on Road Work - No Hydro Control)	165,000	607,745	1,026,475	651,136	1,543,453	1,023,557	403,115
System Access	**2,372,414**	**3,306,569**	**29,214,636**	**3,089,972**	**5,314,658**	**3,821,848**	**2,321,862**
Alterations and Improvements for Load Transfer and System Security	292,959	344,096	219,750	888,426	572,150	471,194	1,028,655
Rebuild Overhead Distribution System	4,843,049	5,037,728	3,825,171	2,454,789	2,466,663	1,874,389	1,118,877
Rebuild Underground Distribution System	1,409,133	2,871,729	1,804,143	2,245,090	2,299,891	1,714,853	2,017,232
Substations	732,398	1,104,439	476,967	643,618	930,273	782,606	1,016,763
Supervisory Control and Communications	244,133	191,859	117,629	272,846	144,088	105,869	231,887
Transformer Replacements and Voltage Conversion	1,139,908	1,596,097	495,203	1,066,708	821,381	585,917	566,332
System Renewal	**8,661,580**	**11,145,948**	**6,938,864**	**7,571,478**	**7,234,446**	**5,534,829**	**5,979,745**
27.6kV Additions	732,398	796,263	601,360	322,926			
Administration - IT			135,924	775,928	45,000	45,000	452,000
Distribution Meters / Wholesale Meter Upgrades			98,360	10,118,954	77,000	77,000	
Rebuild Overhead Distribution System							100,000
Substations		67,485					
Supervisory Control and Communications	48,827	51,988	1,899	94,880	108,214	79,443	36,899
On-Site Emergency Back-up Transformer							5,000,000
System Service	**781,224**	**915,736**	**837,543**	**11,312,688**	**230,214**	**201,443**	**5,588,899**
Administration - Buildings	314,443	247,516	1,080,051	261,256	72,500	66,046	341,615
Administration - IT	2,132,597	830,404	1,493,556	811,937	1,403,474	1,379,477	1,897,210
Major Tools and Safety Equipment	126,949	129,233	13,684	109,329	115,439	107,902	93,333
Fleet	332,020	39,905	468,107	839,811	638,008	583,203	384,762
General Plant	**2,906,009**	**1,247,058**	**3,055,398**	**2,022,334**	**2,229,421**	**2,136,627**	**2,716,920**
Grand Total	**$14,721,227**	**$16,615,311**	**$40,046,440**	**$23,996,472**	**$15,008,738**	**$11,694,747**	**$16,607,427**
Increase/(Decrease) vs Prior Year		**$1,894,084**	**$23,431,129**	**-$16,049,968**	**-$8,987,735**	**-$3,313,991**	**$4,912,680**

The 2010 actual capital additions were $1,894,084 higher than the capital additions approved by the Board in Oakville Hydro's last application. The variances by major project are detailed in Table 2-33.

System Access and System renewal projects were higher than the Board-approved amount, driven by non-discretionary new development and road widening projects, substations, underground rebuilds and transformer replacements and voltage conversion. Substation expenditures were higher than planned due to air breaker retrofits and equipment refurbishments. Underground rebuilds were $1,462,596 higher than the Board-approved amount primarily due to increased spending on Poletrans of $948,134 and retrofitting PMH switchgear of $502,861. In addition, Oakville Hydro added a transformer replacement and voltage conversion in the Woodhaven Park for $424,435. These increases were offset by lower spending than anticipated on Information Technology and Vehicles. Planned additions for SCADA and OMS of $600,000 were delayed until 2012, GIS expenditures were $376,185 lower than planned and computer upgrades planned for 2010 did not take place. The replacement of a Derrick Digger budgeted in 2010 for $300,000 did not occur until 2011.

Table 2-33: Capital Additions by Major Project 2010 Actuals vs. 2010 Board-approved

Major Project	2010 Board-Approved	2010 Actuals	Variance
27.6kV Additions	$400,000	$480,896	$80,896
Distribution Meters / Wholesale Meter Upgrades	732,398	871,927	139,530
New Development / Services	1,075,016	1,346,001	270,985
Road Widening (Dependent on Road Work - No Hydro Control)	165,000	607,745	442,745
System Access	**2,372,414**	**3,306,569**	**934,155**
Alterations and Improvements for Load Transfer and System Security	292,959	344,096	51,137
Rebuild Overhead Distribution System	4,843,049	5,037,728	194,678
Rebuild Underground Distribution System	1,409,133	2,871,729	1,462,596
Substations	732,398	1,104,439	372,042
Supervisory Control and Communications	244,133	191,859	-52,274
Transformer Replacements and Voltage Conversion	1,139,908	1,596,097	456,189
System Renewal	**8,661,580**	**11,145,948**	**2,484,368**
27.6kV Additions	732,398	796,263	63,865
Substations	0	67,485	67,485
Supervisory Control and Communications	48,827	51,988	3,162
System Service	**781,224**	**915,736**	**134,511**
Administration - Buildings	314,443	247,516	-66,926
Administration - IT	2,132,597	830,404	-1,302,193
Major Tools and Safety Equipment	126,949	129,233	2,284
Fleet	332,020	39,905	-292,115
General Plant	**2,906,009**	**1,247,058**	**-1,658,951**
Grand Total	**$14,721,227**	**$16,615,311**	**$1,894,084**

The 2011 actual capital additions were $23,431,129 higher than the 2010 actual capital additions. The variances by major project are detailed in Table 2-34. The main driver behind the increase is the addition of the Glenorchy MTS for $22,860,578. Construction of the 153MW Glenorchy MTS began in August 2010, with the station in-service in July 2011. The MTS was built in order to increase the supply of electricity required to address the Town of Oakville's current and planned growth – primarily in North Oakville.

Normalized capital additions for 2011, excluding the Glenorchy MTS and Smart Meters, were $17,131,592, an increase of $516,281 versus 2010. System Access and General Plant projects were higher than the 2010 Actuals, driven by the installation of two feeders from the Glenorchy MTS for $3,555,771, re-roofing and renovations at Redwood Square for $851,368, the replacement of a Derrick Digger for $297,454 and higher spending on the continued conversion of Oakville Hydro's Geographic Information System of $601,914. These increases were offset by a decrease versus 2010 in System Renewal projects of $4,207,084 driven by Overhead and Underground Rebuilds, Poletrans Replacements, Substation Breaker Retrofits and Transformer Replacements and Voltage Conversion. In addition, meter additions decreased versus 2010 by $658,791 due to a reduction in conversions from bulk metering to suite metering.

Table 2-34: Capital Additions by Major Project 2011 Actuals vs. 2010 Actuals

Major Project	2010 Actuals	2011 Actuals	Variance
27.6kV Additions	$480,896	$26,416,349	$25,935,452
Distribution Meters / Wholesale Meter Upgrades	871,927	213,136	-658,791
New Development / Services	1,346,001	1,558,676	212,675
Road Widening (Dependent on Road Work - No Hydro Control)	607,745	1,026,475	418,730
System Access	**3,306,569**	**29,214,636**	**25,908,067**
Alterations and Improvements for Load Transfer and System Security	344,096	219,750	-124,346
Rebuild Overhead Distribution System	5,037,728	3,825,171	-1,212,556
Rebuild Underground Distribution System	2,871,729	1,804,143	-1,067,586
Substations	1,104,439	476,967	-627,472
Supervisory Control and Communications	191,859	117,629	-74,229
Transformer Replacements and Voltage Conversion	1,596,097	495,203	-1,100,894
System Renewal	**11,145,948**	**6,938,864**	**-4,207,084**
27.6kV Additions	796,263	601,360	-194,902
Administration - IT		135,924	135,924
Distribution Meters / Wholesale Meter Upgrades		98,360	98,360
Substations	67,485	0	-67,485
Supervisory Control and Communications	51,988	1,899	-50,089
System Service	**915,736**	**837,543**	**-78,193**
Administration - Buildings	247,516	1,080,051	832,535
Administration - IT	830,404	1,493,556	663,152
Major Tools and Safety Equipment	129,233	13,684	-115,550
Fleet	39,905	468,107	428,203
General Plant	**1,247,058**	**3,055,398**	**1,808,340**
Grand Total	**$16,615,311**	**$40,046,440**	**$23,431,129**
Normalized Capital Expenditures (ex Glenorchy MTS and Smart Meters)	**$16,615,311**	**$17,131,592**	**$516,281**

The 2012 actual capital additions were $16,049,968 lower than the 2011 actual capital additions. The variances by major project are detailed in Table 2-35. The main driver behind the decrease is the addition of the Glenorchy MTS for $22,860,578 in 2011 partly offset by the addition of Smart Meters for $10,118,954 in 2012.

Normalized capital additions for 2012, excluding the Glenorchy MTS and Smart Meters, were $13,718,170, a decrease of $3,413,422 versus 2011. System Access additions were lower than the 2011 Actuals, driven by the installation of two feeders from the Glenorchy MTS for $3,555,771 in 2011 and lower spending for non-discretionary new development and road widening projects. Lower spending on Overhead Rebuilds and Buildings (the Redwood Square re-roofing and renovation took place in 2011) was offset by increased spending on Load Transfer and System Security (insulated switchgear and underslung switch replacements), Underground Rebuilds, Poletrans replacements, Transformer Replacements and Voltage Conversion, and Vehicles (a double bucket truck and a single bucket truck were replaced in 2012).

Table 2-35: Capital Additions by Major Category 2012 Actuals vs. 2011 Actuals

Major Project	2011 Actuals	2012 Actuals	Variance
27.6kV Additions	$26,416,349	$722,005	-$25,694,343
Distribution Meters / Wholesale Meter Upgrades	213,136	673,701	460,566
New Development / Services	1,558,676	1,043,129	-515,547
Road Widening (Dependent on Road Work - No Hydro Control)	1,026,475	651,136	-375,339
System Access	**29,214,636**	**3,089,972**	**-26,124,664**
Alterations and Improvements for Load Transfer and System Security	219,750	888,426	668,676
Rebuild Overhead Distribution System	3,825,171	2,454,789	-1,370,382
Rebuild Underground Distribution System	1,804,143	2,245,090	440,947
Substations	476,967	643,618	166,651
Supervisory Control and Communications	117,629	272,846	155,217
Transformer Replacements and Voltage Conversion	495,203	1,066,708	571,505
System Renewal	**6,938,864**	**7,571,478**	**632,614**
27.6kV Additions	601,360	322,926	-278,434
Administration - IT	135,924	775,928	640,004
Distribution Meters / Wholesale Meter Upgrades	98,360	10,118,954	10,020,594
Supervisory Control and Communications	1,899	94,880	92,981
System Service	**837,543**	**11,312,688**	**10,475,146**
Administration - Buildings	1,080,051	261,256	-818,795
Administration - IT	1,493,556	811,937	-681,618
Major Tools and Safety Equipment	13,684	109,329	95,645
Fleet	468,107	839,811	371,704
General Plant	**3,055,398**	**2,022,334**	**-1,033,064**
Grand Total	**$40,046,440**	**$23,996,472**	**-$16,049,968**
Normalized Capital Expenditures (ex Glenorchy MTS and Smart Meters)	**$17,131,592**	**$13,718,170**	**-$3,413,422**

The 2013 capital additions (old CGAAP) are projected to be $8,987,735 lower than the 2012 actual capital additions. The variances by major project are detailed in Table 2-36. The main driver behind the decrease is the addition of Smart Meters for $10,118,954 in 2012.

2013 capital additions of $15,008,738 are expected to be $1,290,568 higher than 2011 normalized capital additions, excluding the Glenorchy MTS and Smart Meters. The increase is driven by higher spending on System Access projects of $2,224,686 partially offset by a decrease in System Renewal projects, 27.6kV additions, Buildings and Vehicles totaling $1,050,519. System Access projects are expected to be higher due to increased spending on non-discretionary new development and road widening projects.

Table 2-36: Capital Additions by Major Category 2013 Old CGAAP vs. 2012 Actuals

Major Project	2012 Actuals	2013 Old CGAAP	Variance
27.6kV Additions	$722,005	$1,879,441	$1,157,436
Distribution Meters / Wholesale Meter Upgrades	673,701	479,202	-194,500
New Development / Services	1,043,129	1,412,561	369,432
Road Widening (Dependent on Road Work - No Hydro Control)	651,136	1,543,453	892,317
System Access	**3,089,972**	**5,314,658**	**2,224,686**
Alterations and Improvements for Load Transfer and System Security	888,426	572,150	-316,276
Rebuild Overhead Distribution System	2,454,789	2,466,663	11,874
Rebuild Underground Distribution System	2,245,090	2,299,891	54,801
Substations	643,618	930,273	286,655
Supervisory Control and Communications	272,846	144,088	-128,758
Transformer Replacements and Voltage Conversion	1,066,708	821,381	-245,328
System Renewal	**7,571,478**	**7,234,446**	**-337,033**
27.6kV Additions	322,926	0	-322,926
Administration - IT	775,928	45,000	-730,928
Distribution Meters / Wholesale Meter Upgrades	10,118,954	77,000	-10,041,954
Supervisory Control and Communications	94,880	108,214	13,334
System Service	**11,312,688**	**230,214**	**-11,082,474**
Administration - Buildings	261,256	72,500	-188,756
Administration - IT	811,937	1,403,474	591,537
Major Tools and Safety Equipment	109,329	115,439	6,110
Fleet	839,811	638,008	-201,803
General Plant	**2,022,334**	**2,229,421**	**207,087**
Grand Total	**$23,996,472**	**$15,008,738**	**-$8,987,735**
Normalized Capital Expenditures (ex Glenorchy MTS and Smart Meters)	**$13,718,170**	**$15,008,738**	**$1,290,568**

Table 2-37 details the difference between 2013 Old CGAAP and 2013 New CGAAP. As outlined in Exhibit 2, Tab 6, Oakville Hydro has deferred the implementation of IFRS. In accordance with the Board's guidelines published July 17, 2012, Oakville Hydro implemented changes to its depreciation rates and capitalization policy effective January 1, 2013. Old CGAAP represents the projected capital additions before the change to Oakville Hydro's capitalization policy. New CGAAP represents the projected capital additions after the change to the capitalization policy. The impact of the change to Oakville Hydro's capitalization policy (removal of non-directly attributable overhead costs from capital) is a decrease of $3,313,991.

Table 2-37: Capital Additions by Major Category 2013 New CGAAP vs. 2013 Old CGAAP

Major Project	2013 Old CGAAP	2013 New CGAAP	Variance
27.6kV Additions	$1,879,441	$1,333,282	-$546,160
Distribution Meters / Wholesale Meter Upgrades	479,202	362,879	-116,323
New Development / Services	1,412,561	1,102,130	-310,432
Road Widening (Dependent on Road Work - No Hydro Control)	1,543,453	1,023,557	-519,896
System Access	**5,314,658**	**3,821,848**	**-1,492,810**
Alterations and Improvements for Load Transfer and System Security	572,150	471,194	-100,956
Rebuild Overhead Distribution System	2,466,663	1,874,389	-592,274
Rebuild Underground Distribution System	2,299,891	1,714,853	-585,038
Substations	930,273	782,606	-147,667
Supervisory Control and Communications	144,088	105,869	-38,218
Transformer Replacements and Voltage Conversion	821,381	585,917	-235,463
System Renewal	**7,234,446**	**5,534,829**	**-1,699,617**
Administration - IT	45,000	45,000	0
Distribution Meters / Wholesale Meter Upgrades	77,000	77,000	0
Supervisory Control and Communications	108,214	79,443	-28,770
System Service	**230,214**	**201,443**	**-28,770**
Administration - Buildings	72,500	66,046	-6,454
Administration - IT	1,403,474	1,379,477	-23,998
Major Tools and Safety Equipment	115,439	107,902	-7,537
Fleet	638,008	583,203	-54,805
General Plant	**2,229,421**	**2,136,627**	**-92,794**
Grand Total	**$15,008,738**	**$11,694,747**	**-$3,313,991**

The 2014 capital additions are projected to be $4,912,680 higher than the 2013 projected capital additions. The variances by major project are detailed in Table 2-38. The main driver behind the increase is the addition of an Emergency Back-up Transformer for the Glenorchy MTS for $5,000,000. This project is discussed in more detail in the DS Plan. Decreases in 27.6kV additions and non-discretionary road widening projects of $912,308 and $620,442 respectively, are offset by increased spending in Information Technology of $924,733 and System Renewal of $444,917. Investment in Information Technology has increased versus 2013 due to the adjustment of a capital lease for $738,210 between Oakville Hydro and a third party for optical fibres. The optical fibres are used as communications infrastructure for operation of Oakville Hydro's distribution system. This adjustment is discussed in more detail in Exhibit 2, Tab 2, Schedule 5.

Table 2-38: Capital Additions by Major Category 2014 Bridge Year vs. 2013 Test Year

Major Project	2013 New CGAAP	2014 New CGAAP	Variance
27.6kV Additions	$1,333,282	$420,973	-$912,308
Distribution Meters / Wholesale Meter Upgrades	362,879	481,706	118,827
New Development / Services	1,102,130	1,016,068	-86,062
Road Widening (Dependent on Road Work - No Hydro Control)	1,023,557	403,115	-620,442
System Access	**3,821,848**	**2,321,862**	**-1,499,985**
Alterations and Improvements for Load Transfer and System Security	471,194	1,028,655	557,461
Rebuild Overhead Distribution System	1,874,389	1,118,877	-755,513
Rebuild Underground Distribution System	1,714,853	2,017,232	302,379
Substations	782,606	1,016,763	234,157
Supervisory Control and Communications	105,869	231,887	126,018
Transformer Replacements and Voltage Conversion	585,917	566,332	-19,586
System Renewal	**5,534,829**	**5,979,745**	**444,917**
Administration - IT	45,000	452,000	407,000
Distribution Meters / Wholesale Meter Upgrades	77,000	0	-77,000
Rebuild Overhead Distribution System	0	100,000	100,000
Supervisory Control and Communications	79,443	36,899	-42,545
Transformer Replacements and Voltage Conversion	0	5,000,000	5,000,000
System Service	**201,443**	**5,588,899**	**5,387,455**
Administration - Buildings	66,046	341,615	275,569
Administration - IT	1,379,477	1,897,210	517,733
Major Tools and Safety Equipment	107,902	93,333	-14,569
Fleet	583,203	384,762	-198,441
General Plant	**2,136,627**	**2,716,920**	**580,293**
Grand Total	**$11,694,747**	**$16,607,427**	**$4,912,680**

Treatment of Projects with a Life Cycle Greater than One Year

Oakville Hydro's accounting policy is to include projects in fixed assets when they are completed (energized). Capital projects which are not yet completed are included in Work in Progress ('WIP"). Capital projects with a life cycle greater than one year will be carried over from one year to the next in WIP. Once completed, expenditures are removed from WIP and capitalized to fixed assets.

Treatment of Cost of Funds

Oakville Hydro's accounting policy is to expense borrowing costs. It does not capitalize interest on capital projects.

Components of Other Capital Expenditures

Oakville Hydro does not have other capital expenditures, such as non-distribution activities, for which it needs to provide components.

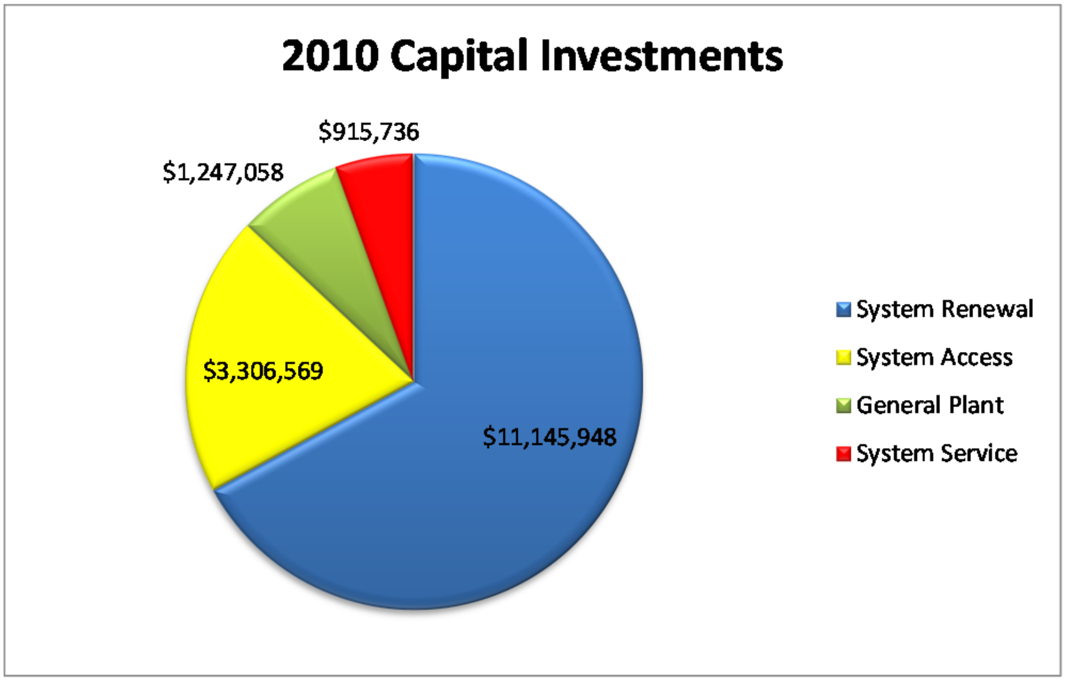
2010 Capital Additions

Chapter 5 of the Filing Requirements sets out the Investment Categories for grouping capital investments according to the driver of the expenditure. Table 2-39, 2010 Capital Investments, provides a breakdown of historical capital spending in accordance with the Board's Investment Categories.

Table 2-39 - 2010 Capital Investments

Major Project	Total
27.6kV Additions	$480,896
Distribution Meters / Wholesale Meter Upgrades	871,927
New Development / Services	1,346,001
Road Widening (Dependent on Road Work - No Hydro Control)	607,745
System Access	**3,306,569**
Alterations and Improvements for Load Transfer and System Security	344,096
Rebuild Overhead Distribution System	5,037,728
Rebuild Underground Distribution System	2,871,729
Substations	1,104,439
Supervisory Control and Communications	191,859
Transformer Replacements and Voltage Conversion	1,596,097
System Renewal	**11,145,948**
27.6kV Additions	796,263
Substations	67,485
Supervisory Control and Communications	51,988
System Service	**915,736**
Administration - Buildings	247,516
Administration - IT	830,404
Major Tools and Safety Equipment	129,233
Fleet	39,905
General Plant	**1,247,058**
Grand Total	**$16,615,311**

Oakville Hydro's capital additions for 2010 were $16,615,311, an increase of $1,894,084 over the 2010 Cost of Service application which projected capital additions of $14,721,227. These projects have been categorized into System Access, System Renewal, System Service and General Plant in accordance with Chapter 5 of the Filing Requirements. The following graph illustrates the breakout of each of the Investment Categories.



System Access Projects - $3,306,569

Projects in the System Access category are driven by statutory, regulatory or other obligations on the part of Oakville Hydro to provide customers with access to the distribution system. Oakville Hydro spent $3,256,569 on system access projects in 2010.

27.6kV Additions - $480,896

The 2010 capital program included $480,896 for the addition of 27.6kV overhead and underground circuits and switches at the following locations:

- Rebecca Street/Jones Street – an additional underground 27.6kV circuit was constructed to improve security and reliability and provide for local load growth.

- Wyecroft Road – an additional 27.6kV circuit was constructed on an existing overhead line. This improved security and reliability and provided for local load growth.
- North Service Road E/Joshua Creek Drive – an additional 27.6kV circuit was constructed to facilitate easier load transfers between Hydro One transformer stations. Hydro One had de-rated station ratings due to equipment problems.

Distribution Meters/Wholesale Meter Upgrades - $871,927

The 2010 capital program included $871,927 for distribution and wholesale meter upgrades. This was comprised of $378,596 for condominium retrofits to individual metering, $257,900 for wholesale meters and $235,431 for residential meters to comply with industry standards.

New Development/Services - $3,833,449

Oakville Hydro Portion $1,346,001 – Contributed Capital $2,487,448

The 2010 capital program included $3,833,449 for the cost of designing and installing electrical distribution infrastructure required for new subdivisions and commercial areas under development in Oakville. Of this total, $1,346,001 was funded by Oakville Hydro and the remaining $2,487,448 was funded through capital contributions.

Road Widening – $1,734,466

Oakville Hydro Portion $607,745 – Contributed Capital $1,126,721

The 2010 capital program included $1,734,466 for the cost of relocating hydro facilities due to road widening work by the Town of Oakville, the Region of Halton and the Ministry of Transportation. Of this total, $607,745 was funded by Oakville Hydro and the remaining $1,126,721 was funded through capital contributions. These types of projects are non-discretionary.

System Renewal Projects- $11,145,948

As defined in the Chapter 5 Filing Requirements, projects in the System Renewal category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). $11,145,948 was spent on system renewal projects in 2010.

Load Transfer and System Security - $344,096

The 2010 capital program included $225,268 for the upgrading and replacement of submersible transformer tops and commercial vault tops that were in poor condition. This is a multi-year program to eliminate existing rusting, damaged and corroding roof sections from the system. The replacement program improves safety and reduces outages. The new tops are constructed with galvanized coating and have a longer life expectancy.

The 2010 capital program also included $118,828 for the replacement of 600 Amp porcelain high voltage terminations and surge arresters.

Rebuild Overhead Distribution System - $5,037,728

The 2010 capital program included $5,037,728 for rebuilding the overhead distribution system.

As part of its Overhead Rebuild plan, Oakville Hydro replaced primary and secondary overhead wires, cable terminations and transformers that were assessed to be unsafe or non-compliant with standards, at a cost of $2,603,395. Completion of these projects improved reliability and enhanced safety while reducing future maintenance costs.

The 2010 capital program included $1,086,708 to rebuild, replace and re-route pole lines that were installed in the rear of residential properties to safer, more accessible areas. This expenditure was part of a multi-year Rear-Lot distribution replacement project.

The 2010 capital program also included $824,830 for the replacement of aging overhead pole lines throughout the distribution system. Poles requiring replacement are identified through an annual inspection program. Oakville Hydro contracts out its inspection program to a and specialized pole testing contractor who conducts visual inspections of poles less than 15 years old and extensive testing of poles greater than 15 years old. Remedial treatment is applied during inspection as required to extend the useful life of the pole. The contractor also assesses the pole for mechanical deficiencies such as ground wire or cross arm issues. The contractor reports any poles that cannot be remedied through treatment and which require replacement. A report is provided to Oakville Hydro after completion of the annual testing and includes a summary of testing, treatment and recommended action, including poles verbally reported for immediate replacement. A replacement schedule is determined based on the report findings. Other areas for overhead reinvestment were identified through patrols of the overhead distribution system, where crews identified the worst condition areas of the system which were scheduled for replacement.

In 2010, Oakville Hydro changed its pole testing cycle from five years to seven years to coincide with the 7-year lifespan of the remedial treatment applied at the time of the pole inspection. However, this did not result in a reduction of the number of poles expected to need replacement. This is because Oakville Hydro improved its testing method in 2009 and found that poles previously inspected and identified as being sound were subsequently determined to be in need of replacement.

Poles are normally recommended for immediate replacement when testing indicates that the remaining strength of the poles is less than 50%. Poles are recommended for replacement within one to two years when testing indicates the remaining strength is between 50% and 67%. The majority of the poles recommended for replacement are approximately 45 years old. During the rebuilds, pole framing is upgraded to current standards, all connections and supports are checked, and where necessary porcelain insulators are replaced with polymer insulators. The pole replacement program improves system reliability, improves safety and reduces maintenance costs.

Also included in the 2010 capital program was $469,501 for the re-insulation of existing 27.6kV and 4.16kV circuits with polymer insulators. These circuits were originally installed with porcelain insulators which are less reliable and have higher maintenance costs. These replacements also eliminated the risk of broken porcelain falling to the ground.

Rebuild Underground Distribution System- $2,871,729

The 2010 capital program included $2,871,729 for rebuilding the underground distribution infrastructure.

The underground rebuild program included $1,241,094 for the continuation of a multi-year program initiated in 2005 to eliminate Poletrans. Poletrans are streetlight poles with embedded transformers. These were installed between 1965 and 1971 and have safety and operational problems. In addition, replacement parts are not readily available. This project included cable replacement, new pad-mounted transformers and improved safety and reliability.

The capital program included $470,370 for rebuilding the primary underground distribution system in the McCraney area. The project involved the installation of duct and new cable to improve the reliability in the area. The cables requiring replacement were over 40 years old and had experienced failure.

$844,647 was spent in 2010 on the continuation of a multi-year program to retrofit and refurbish switchgear. In 2010, existing PMH (PMH is a brand name for air insulated pad-mounted switch gear) switchgear was replaced with new Vista switchgear.

Substations - $1,104,439

In 2010 Oakville Hydro owned 20 municipal substations, the purpose of which is to step down the power from the four Hydro One owned transformer stations located at the four corners of Oakville. These municipal substations receive power from the transformer station feeders at 27.6kV, and step it down to either 4kV or 13.8kV. The power is then distributed to residential and commercial customers in South Oakville, through Oakville Hydro's distribution network.

Most of the substations were built between 1950 and 1970. North Oakville is serviced with 13.8kV circuits.

In 2010, $1,104,439 was spent on substation replacements and retrofits. This included the replacement of the oil circuit breakers at the Cross Municipal Substation for $352,639 and the replacement of the air magnetic circuit breakers at the Margaret Municipal Substation for $407,411. The existing breakers had reached the end of their useful lives and were replaced by breakers which are less costly to maintain, equipped with better safety features and provide enhanced operational data. In addition, $212,387 was spent on substation equipment refurbishment and upgrades.

Supervisory Control and Communications - $191,859

The System Renewal portion of the 2010 capital spend for supervisory control and communications was $191,859. This was for the continuation of a multi-year program to upgrade remote terminal units connecting remote switches to SCADA. The remote terminal units are subject to harsh weather conditions and have an average life span of 15 years. The units replaced in 2010 were approximately 20 years old.

Transformer Replacements and Voltage Conversion - $1,596,097

The 2010 capital program included $1,596,097 for transformer replacements and voltage conversion within Oakville Hydro's service area. Oakville Hydro incurred costs of $424,435 associated with the overhead rear lot primary system conversion to an underground system in Woodhaven Park, $238,587 to complete a 27.6kV voltage conversion (from 4.16kV) at Howard Avenue and Park Avenue and $334,898 was incurred for the installation of new overhead and underground transformers in various locations throughout Oakville. An additional $598,177 represented emergency spare transformers in inventory, which were reclassified to fixed assets as per Board guidelines.

System Service Projects - $915,736

Projects in this category are driven by Oakville Hydro's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Oakville Hydro spent $915,736 on system service projects in 2010.

27.6kV Additions - $796,263

The majority of the 2010 capital program for System Service Projects was spent on 27.6kV additions. $405,738 was spent on switching improvements in the Winston Park area. Existing PMH switchgear (PMH is a brand name for air insulated pad-mounted switch gear) were replaced with G&W switchgear (G&W is a supplier of electricity materials) to improve reliability of the distribution system. $125,306 was for the installation of new G&W switchgear at the Kerr St. municipal water pumping station. An additional $265,217 was incurred to replace remote controlled switches. This was part of an ongoing program to upgrade older switches with more efficient and reliable units. As a result, the Control Room was able to maintain the grid in a more efficient manner and reduce maintenance costs.

General Plant Projects - $1,247,058

Projects in this category are driven by Oakville Hydro's evolving requirements for capital to support day to day business and operations activities. Oakville Hydro spent $1,297,058 on General Plant projects in 2010.

Buildings - $247,516

The 2010 capital plan included $72,940 for HVAC replacement and installation and $69,762 for an extension to the Building Automation System (HVAC and lighting controls for the meter shop, garage, warehouse, cranebay area and Fibre rooms at Redwood Square). The remaining capital additions in this category were for leasehold improvements at Redwood Square.

Information Technology - $830,404

The 2010 capital plan included $830,404 for computer hardware and software. Capital expenditures on infrastructure were $554,294. This included $304,470 for a phone system upgrade. Oakville Hydro was using an outdated phone system which was in need of a major software upgrade to bring the system up to a "current" configuration. This project included the implementation, migration of configurations, system security and removal of obsolete hardware. The main drivers for this project were to reduce the overall costs and improve system capabilities and end user features. Also included in infrastructure expenses was $92,215 for Microsoft Licenses and Software Assurance.

Capital expenditures for Enterprise Resource Planning ("ERP") Enhancements were $149,382. In 2006 Oakville Hydro migrated from JD Edwards to Microsoft's Great Plains ("GP"), its current ERP system. In 2010, Oakville Hydro upgraded to GP Version 10 to address gaps in the current version of GP and ensure that the application was kept current to eliminate any additional costs from third party vendors for features no longer under support based on Microsoft's upgrade/support path. BDO Canada implemented the first GP version and performed the upgrade.

- Capital expenditures for the conversion of Oakville Hydro's network system records from an AutoCAD system to a Geographic Information System (GIS) were $126,728. Prior to 2010, the network system records only contained drawings for the high voltage express feeder operating grid from the four transformer stations. Oakville Hydro selected the company ESRI to provide its GIS system, the ArcGIS Platform. The conversion of the GIS system took place over 2010 and 2011 with further enhancements in 2012 onwards and involved the inclusion of the entire distribution system. The ESRI-based GIS system offers various productivity saving features, which began to materialize in 2012. Some examples are listed below:
    - Elimination of duplicate records

- Decrease reconciliation costs between Engineering & Operations for field information
- Ease in locating documents - requests from other utilities, customers, and others,
- Improved records accuracy will reduce amount of field verification for design work
- Improving information for locates
- Improving information for operations & maintenance
- Locating data and documents
- Providing information to field crews
- System contingency planning and optimization
- Service calls and Outage Management

The full system network model based on GIS Arc-FM facilitates operational requirements such as an Outage Management System, optimization of system losses through engineering software, and mobile computing, opening up many opportunities to provide effective information exchange with field crews. Arc-FM is an extension of ESRI's ArcGIS platform and is a complete enterprise utility solution for editing, modeling, maintenance, and management of facility and land base information for electrical utilities.

Major Tools and Safety Equipment - $129,233

The 2010 capital program included $129,233 for tools required to perform work safely in Line Operations, the protection and control the meter departments.

2011 Capital Additions

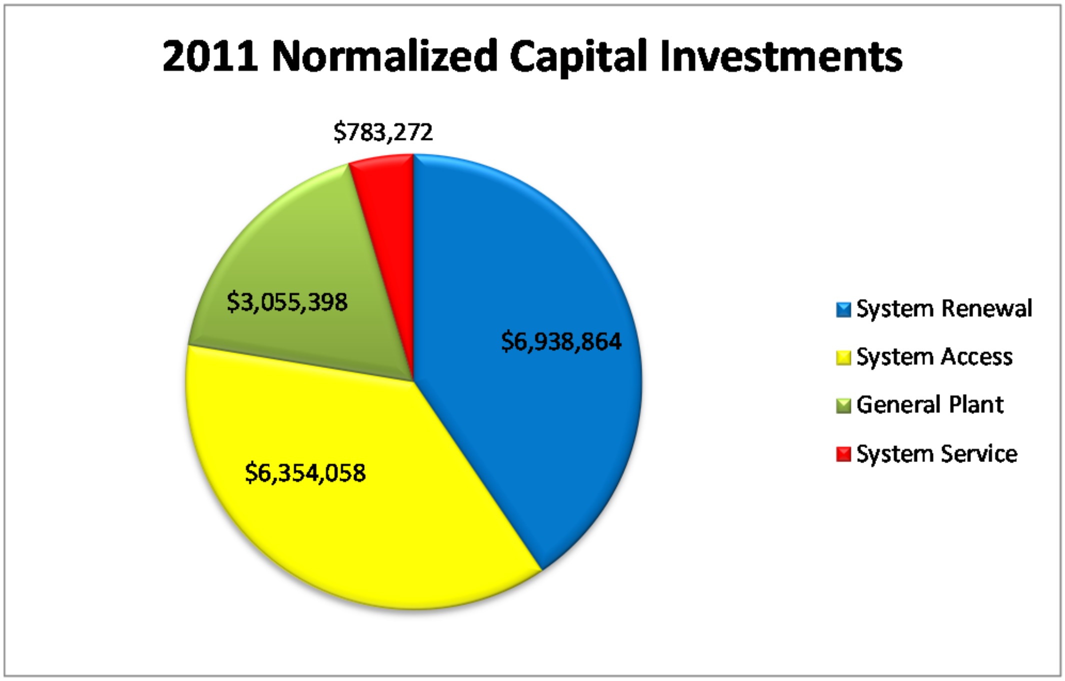
Chapter 5 of the Filing Requirements sets out the Investment Categories for grouping capital investments according to the driver of the expenditure. Table 2-40, 2011 Capital Investments, provides a breakdown of historical capital spending in accordance with the Board's Investment Categories.

Table 2-40 - 2011 Capital Investments

Major Project	Total	Ex Glenorchy MTS and Smart Meters (1)
27.6kV Additions	$26,416,349	$3,555,771
Distribution Meters / Wholesale Meter Upgrades	213,136	213,136
New Development / Services	1,558,676	1,558,676
Road Widening (Dependent on Road Work - No Hydro Control)	1,026,475	1,026,475
System Access	**29,214,636**	**6,354,058**
Alterations and Improvements for Load Transfer and System Security	219,750	219,750
Rebuild Overhead Distribution System	3,825,171	3,825,171
Rebuild Underground Distribution System	1,804,143	1,804,143
Substations	476,967	476,967
Supervisory Control and Communications	117,629	117,629
Transformer Replacements and Voltage Conversion	495,203	495,203
System Renewal	**6,938,864**	**6,938,864**
27.6kV Additions	601,360	601,360
Administration - IT	135,924	135,924
Distribution Meters / Wholesale Meter Upgrades	98,360	44,089
Supervisory Control and Communications	1,899	1,899
System Service	**837,543**	**783,272**
Administration - Buildings	1,080,051	1,080,051
Administration - IT	1,493,556	1,493,556
Major Tools and Safety Equipment	13,684	13,684
Fleet	468,107	468,107
General Plant	**3,055,398**	**3,055,398**
Grand Total	**$40,046,440**	**$17,131,592**

(1) Excluding Glenorchy Municipal Transformer Station and Smart Meters to allow comparisons from year to year.

Oakville Hydro's capital additions for 2011 were $40,046,440, an increase of $23,431,129 over 2010, driven primarily by the construction of the new Glenorchy Municipal Transformer Station in North Oakville. This project is discussed in further detail in this section under System Access. The following graph illustrates the breakout of each of the Investment Categories.



2011 capital additions excluding the Glenorchy Municipal Transformer Station and smart meters were $17,131,592, an increase of $566,281 versus 2010, driven by increased spending in General Plant and the construction of new feeders from the Glenorchy Municipal Transformer Station, partially offset by decreased spending on overhead and underground rebuilds.

Similar to 2010, 2011 projects have been categorized into System Access, System Renewal, System Service and General Plant as per the Chapter 5 Consolidated Distribution System Plan Filing Requirements issued by the Board on March 28, 2013.

System Access Projects - $29,214,636

Projects in the System Access category are driven by statutory, regulatory or other obligations on the part of Oakville Hydro to provide customers with access to the distribution system. In 2011, Oakville Hydro spent $29,214,636 on system access projects.

27.6kV Additions - $26,416,349

The main driver of the expenditures in this category was the design and construction of the Glenorchy Municipal Transformer Station for $22,860,578. This included the purchase of land for $1,421,336. Construction of the 153MW Glenorchy Municipal Transformer Station began in August 2010 and the station was in-service in July 2011. The Glenorchy Municipal Transformer Station was built in order to increase the supply of electricity required to address the Town of Oakville's current and planned growth, primarily in North Oakville. Capacity will be utilized further by the new Oakville Hospital which is expected to be open in late 2015 and by Milton Hydro who, as of August 2013, is connected to the Glenorchy Municipal Transformer Station as an embedded distributor.

In its 2011 IRM application (EB-2010-0104), Oakville Hydro received approval for the recovery of the incremental capital costs associated with the design and construction of the Municipal Transformer Station. In its Decision and Order, the Board found that the capital costs incurred were prudent and that Oakville Hydro had provided adequate evidence that potential alternatives were analyzed and that the completion of the project represented the most cost-effective alternative for ratepayers. Oakville Hydro recovered its costs through an Incremental Capital Module ("ICM") Rate Rider which will expire on April 30, 2014.

The remaining $3,555,771 in 27.6kV additions was spent on the construction of feeders from the Glenorchy Municipal Transformer Station, including cabling, conduit structure, switching, overhead circuits and energization.

Distribution Meters/Wholesale Meter Upgrades - $213,136

The 2011 capital program included $213,136 for the installation of meters for all customer classes to comply with industry standards. The majority of the program was related to multi-residential meters and a portion of the capital was spent on the conversion from bulk metering to individual suite metering for multi-residential dwellings.

New Development/Services - $5,806,718

Oakville Hydro Portion $1,558,676 – Contributed Capital $4,248,043

The 2011 capital program included $5,806,718 for the cost of designing and installing electrical distribution infrastructure required for new subdivisions and commercial areas under development in Oakville. Of this total, $1,558,676 was funded by Oakville Hydro and the remaining $4,248,043 was funded through capital contributions.

Road Widening – $1,484,480

Oakville Hydro Portion $1,026,475 – Contributed Capital $458,005

The 2011 capital program included $1,484,480 for the cost of relocating hydro facilities due to road widening work by the Town of Oakville, the Region of Halton and the Ministry of Transportation. Of this total, $1,026,475 was funded by Oakville Hydro and the remaining $458,005 was funded through capital contributions. These types of projects are non-discretionary.

System Renewal Projects - $6,938,864

As defined in the Chapter 5 Filing Requirements , projects in the System Renewal category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. “failure”). Oakville Hydro spent $6,938,864 on system renewal projects in 2011.

Load Transfer and System Security - $219,750

The 2011 capital program included $95,973 for the upgrading and replacement of submersible transformer covers that were in poor condition. This is a multi-year program to eliminate existing rusting, damaged and corroded roof sections from the system. The replacement program improves safety and reduces outages. The new tops are constructed with galvanized coating and have a longer life expectancy.

2011 also included $123,777 for the replacement of 600 Amp porcelain high voltage terminations and surge arresters.

Rebuild Overhead Distribution System - $3,825,171

The 2011 capital program included $3,825,171 for rebuilding the overhead distribution system.

As part of its Overhead Rebuild plan, Oakville Hydro replaced primary and secondary overhead wires, cable terminations and transformers that were assessed to be unsafe or non-compliant with standards, at a cost of $1,877,952. Completion of these projects improved reliability and enhanced safety while reducing future maintenance costs. This represents a decrease versus 2010 during which $2,603,395 was added to capital for similar projects.

The 2011 capital program included $767,177 for the replacement of aging overhead pole lines throughout the distribution system. A description of Oakville Hydro's pole replacement program is provided in the 2010 capital program section.

The 2011 capital additions also included $498,909 to rebuild, replace and re-route pole lines that were installed in the rear of residential properties to safer, more accessible areas. This expenditure was part of a multi-year Rear-Lot distribution replacement project. $1,086,708 was added to capital in 2010.

Also included in the 2011 capital program was $302,568 for the re-insulation of existing 27.6kV and 4.16kV circuits with polymer insulators. These circuits were originally installed with porcelain insulators which are less reliable and have higher maintenance costs. These replacements also eliminated the additional risk of broken porcelain. $149,740 was incurred to replace the secondary bus on Maple Grove Road which was found to be undersized and had experienced failure due to overloading.

$183,206 was spent on the replacement of various 13.8kV and 27.6kV 600 Amp switches as part of overhead rebuilds in accordance with Oakville Hydro's asset renewal program.

Rebuild Underground Distribution System - $1,804,143

The 2011 capital program included $1,804,143 for rebuilding the underground distribution infrastructure.

The capital program included $562,928 for rebuilding the primary underground distribution system in the Holton Heights area and $203,417 for a similar rebuild in the Spring Garden area. These projects involved the installation of duct and new cable to improve the reliability in the area.

Capital additions included $539,603 for the continuation of a multi-year program to refurbish switchgear. In 2011, existing PMH switchgear was replaced with gas-insulated switchgear.

Capital additions also included $297,650 to replace non-vented 28kV transformer bushing inserts and elbows throughout various areas in Oakville as identified through inspections by the Operations department.

The underground rebuild program also included $122,336 for the continuation of a multi-year program initiated in 2005 to eliminate Poletrans. Poletrans are streetlight poles with embedded transformers. These were installed between 1965 and 1971 and have safety and operational problems. In addition, replacement parts are not readily available. This project included cable replacement, new pad-mounted transformers with the outcome being improved safety and reliability. Capital additions for 2011 were lower than the 2010 figure of $1,241,094. In 2011, some of the poletrans elimination projects were delayed due to other priorities and the availability of underground construction resources.

Substations - $476,967

In 2011, Oakville Hydro owned 20 municipal substations, the purpose of which is to step down the power from the four Hydro One owned transformer stations located at the four corners of Oakville as well as the Oakville Hydro owned Glenorchy Municipal Transformer Station.

These municipal substations receive power from the transformer station feeders at 27.6kV, and step it down to either 4kV or 13.8kV. The power is then distributed to residential and commercial customers in South Oakville, through Oakville Hydro's distribution network. Most of the substations were built between 1950 and 1970.

In 2011, $476,967 was spent on substation replacements and retrofits. This included the replacement of the transformer at the Sunset Municipal Substation for $304,712. This was necessitated due to findings during testing. The remaining expenditures were for substation equipment refurbishment and upgrades including the installation of fiber optic cable at the Morden Municipal Substation, and upgrades recommended by the Electrical Safety Authority's (ESA) Continuous Safety Services (CSS) program.

Supervisory Control and Communications - $117,629

The System Renewal portion of the 2011 capital spend for supervisory control and communications was $117,629. This was for the continuation of a multi-year program to upgrade remote terminal units connecting remote switches to SCADA. The remote terminal units are subject to harsh weather conditions and have an average life span of 15 years. The units replaced in 2011 were between 20 and 25 years old.

Transformer Replacements and Voltage Conversion - $495,203

The 2011 capital program included $495,203 for transformer replacements and voltage conversion.

Capital additions included $237,298 to decommission the Allan Street municipal substation which is located in the basement of an apartment building. Some of the substation components experienced failure and the age of the assets was beyond end of useful life. Some loads were converted to 27.6kV distribution and others were redistributed to other stations. The remainder of the load re-distribution and decommissioning will be completed in 2013.

Capital additions included $177,303 to complete a 27.6kV voltage conversion (from 4kV) on Argus Road. $80,602 was for the installation of new overhead/underground transformers in various locations throughout Oakville.

System Service Projects - $837,543

Projects in the category are driven by Oakville Hydro's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Oakville Hydro spent $837,543 on system service projects in 2011.

27.6kV Additions - $601,360

The majority of the 2011 capital program for System Service Projects was spent to replace remote controlled switches at a cost of $576,784. This was part of an ongoing program to upgrade older switches with more efficient and reliable units. The Control Room is able to maintain the grid in a more efficient manner and reduce maintenance costs. $24,576 was spent on switching improvements in the Winston Park area, a completion of the project begun in 2010.

Information Technology - $135,924

Capital expenditures in information technology included $135,924 for upgrades to the Supervisory Control and Data Acquisition ("SCADA") system for field communications. In November 2010, Oakville Hydro engaged a third party, Costello Associates, to perform an Operational Telecommunications Study to review and assess its existing SCADA telecommunication systems and communications alternatives for future utility technical field applications. Based on internal reviews and the study's findings, Oakville Hydro replaced its voice radio communication equipment in 2011. The existing system was over 20 years old and utilized outdated analog technology. The existing system was also lacking some fundamental features including an emergency call button for timely response in the unlikely event of an injury, or call display to enable efficient radio communication. Prior to replacement the desktop units used by office staff to communicate to field staff were failing and required frequent maintenance. The replacement system was deployed using digital communication technology, contained features such as GPS location, emergency call button, and call display.

Distribution Meters/Wholesale Meter Upgrades - $98,360

Capital additions included $54,271 for the initial technology costs for the smart metering roll-out, not completed until 2012. The smart metering roll-out is discussed in more detail in the 2012 section on capital additions.

General Plant Projects - $3,055,398

Projects in this category are driven by Oakville Hydro's evolving requirements for capital to support day to day business and operations activities. Oakville Hydro spent $3,055,398 on General Plant projects in 2011.

Buildings - $1,080,051

The 2011 capital program included $851,638 for the renovation and reroofing of the office space at 861 Redwood Square which was constructed in 1994. These projects were required to replace the roof which was found to have significant blistering and to optimize and reconfigure the second floor of Oakville Hydro's office space to accommodate existing and additional staff in the Engineering, Organizational Effectiveness, Finance and Information Technology departments. The 2011 renovation was the first major renovation and the costs included expenditures associated with a space optimization study, construction costs, reconfiguration costs, carpet replacement, and furniture.

The remaining capital additions in this category included HVAC replacement/installation in the cafeteria and employee locker room for $92,180 and installation of security systems at municipal substations for $47,912.

Information Technology - $1,493,556

The 2011 capital plan included $1,493,556 for computer hardware and software.

Capital expenditures included $728,642 for the continued conversion of Oakville Hydro's Geographic Information System ("GIS"). Oakville Hydro converted its network system records from an AutoCAD system to GIS over 2010 and 2011. The conversion involved the inclusion of the entire distribution system and is discussed in more detail in the 2010 and 2012 capital additions sections.

Capital expenditures included $382,619 for Infrastructure including:

- $120,167 for PC upgrades and replacements
- $105,063 for data centre upgrades which included the following equipment as part on the ongoing new technologies required to run the data center and Disaster Recovery sites.
- A/C Unit
- Fire Suppression
- UPS Upgrade
- System Monitoring Software
- Miscellaneous Microsoft Server Software

Capital expenditures included $194,074 for Great Plains and Business Excellence enhancements. This included $102,957 for GP enhancements for inventory management. In 2010, as part of a major business improvement effort ("Business Excellence"), Oakville Hydro initially mapped and re-designed the three business processes that were involved in Inventory and Materials Management. The goals were to:

- achieve significant improvement in material forecasting

- reduce inventory levels in the warehouse
- Improve the efficiencies within the warehouse
- increase job / project material availability in order to improve overall efficiency

Processes were standardized and system solutions were planned for 2011 and 2012 to support these initiatives. The most notable one that is currently in motion is the Quadra Solution (ERTH Corporation) – joint development is currently underway with ERTH to develop and roll out a two-phase Project Estimating / Material Forecast application linked to Great Plains (Wennsoft). The first phase (basic functionality with framing standards and inventory material plus contract unit costs) was completed October 31, 2011. The second phase (with greater GP/Wennsoft integration and project / program scheduling) began in 2012 with full implementation to be completed in 2013. The tangible benefits of this new application will appear in 2013 with easier project cost estimation, more accurate material forecasts and ability to plan and manage the Construction program.

Also included in GP and Business Excellence Enhancements was $88,997 for the continuation of the upgrade to GP Version 10.

Capital expenditures included $188,220 for Organizational Effectiveness. This expenditure relates to Oakville Hydro's Occupational Health and Safety Management System ("OHSMS"). In 2011, Oakville Hydro, with the launch of its multi-year 'Stayin' Alive' Health and Safety Program, committed to a key strategic goal to implement OHSMS across the business in order to continue to promote and enhance a safe work environment. OHSMS aims to continuously improve safety performance through the effective management of risks and activities in the workplace. The safety management system/program that Oakville Hydro has chosen to adopt is CSA Z1000 which provides an integrated safety system that will enable the organization to continuously improve its health and safety performance, thus preventing injuries. Oakville Hydro selected the Springboard Software, an Automated Management System to support its Health and Safety program. Springboard provides document management, training management and communication, risk management and regulatory compliance, corrective action and reporting and analysis.

Major Tools and Safety Equipment - $13,684

The 2011 capital program included $13,684 for tools required to perform work safely in Line Operations, the protection and control department and the meter department.

Fleet - $468,107

The 2011 capital program included $468,107 to replace selected vehicles in its fleet. This included replacement of one dump truck at a cost of $68,418 (7 years old), two pickup trucks at a cost of $74,765 (10 and 11 years old), and a Digger Derrick truck at a cost of $297,454.

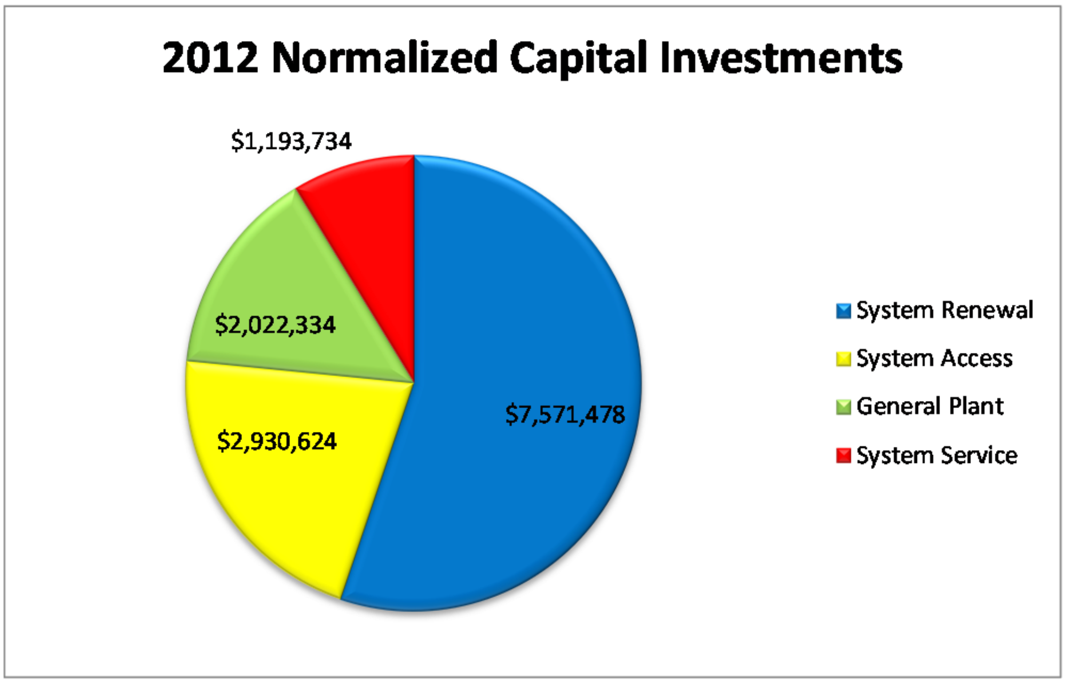
2012 Capital Additions

Chapter 5 of the Filing Requirements sets out the Investment Categories for grouping capital investments according to the driver of the expenditure. Table 2-41, 2012 Capital Investments, provides a breakdown of historical capital spending in accordance with the Board's Investment Categories.

Table 2-41 - 2012 Capital Investments

Major Project	Total	Ex TS and Smart Meters
27.6kV Additions	$722,005	$562,657
Distribution Meters / Wholesale Meter Upgrades	673,701	673,701
New Development / Services	1,043,129	1,043,129
Road Widening (Dependent on Road Work - No Hydro Control)	651,136	651,136
System Access	**3,089,972**	**2,930,624**
Alterations and Improvements for Load Transfer and System Security	888,426	888,426
Rebuild Overhead Distribution System	2,454,789	2,454,789
Rebuild Underground Distribution System	2,245,090	2,245,090
Substations	643,618	643,618
Supervisory Control and Communications	272,846	272,846
Transformer Replacements and Voltage Conversion	1,066,708	1,066,708
System Renewal	**7,571,478**	**7,571,478**
27.6kV Additions	322,926	322,926
Administration - IT	775,928	775,928
Distribution Meters / Wholesale Meter Upgrades	10,118,954	0
Supervisory Control and Communications	94,880	94,880
System Service	**11,312,688**	**1,193,734**
Administration - Buildings	261,256	261,256
Administration - IT	811,937	811,937
Major Tools and Safety Equipment	109,329	109,329
Fleet	839,811	839,811
General Plant	**2,022,334**	**2,022,334**
Grand Total	**$23,996,472**	**$13,718,170**

Oakville Hydro's capital additions for 2012 were $23,996,472 a decrease of $16,049,968 over 2011. The 2011 capital additions included the construction of the new Glenorchy Municipal Transformer Station in North Oakville. This is partly offset by the capitalization of Smart Meters in 2012 of $10,118,954 which will be discussed further in the System Service section. The following graph illustrates the breakout of each of the Investment Categories.



2012 capital additions excluding the Glenorchy Municipal Transformer Station and smart meters were $13,718,170, a decrease of $3,413,421 versus 2011, mainly due to the addition of the Glenorchy feeders in 2011 in the System Access category.

Similar to 2010 and 2011, 2012 projects have been categorized into System Access, System Renewal, System Service and General Plant as per the Chapter 5 Consolidated Distribution System Plan Filing Requirements issued by the Board on March 28, 2013.

System Access Projects - $3,089,972

Projects in the System Access category are driven by statutory, regulatory or other obligations on the part of Oakville Hydro to provide customers with access to the distribution system. Oakville Hydro spent $3,089,972 on system access projects in 2012.

27.6kV Additions - $722,005

The 2012 capital program included $348,925 for Phase II of the feeder construction from the Glenorchy Municipal Transformer Station, including cabling, duct, switching, isolation and energization.

Capital additions included $213,732 for a feeder extension at Winston Churchill Blvd consisting of a three phase circuit extension required to improve security to the local area and allow for future new customer connections.

The 2012 capital program also included $159,348 for further capital work on the Glenorchy Transformer Station (TS). This project is discussed in detail in the 2011 capital section.

Distribution Meters/Wholesale Meter Upgrades - $673,701

The 2012 capital program included $673,701 for the installation of residential meters to comply with industry standards and a portion of the capital was spent on the conversion from bulk metering to individual suite metering for multi-residential dwellings

New Development/Services - $5,443,261

Oakville Hydro Portion $1,043,129 – Contributed Capital $4,400,132

The 2012 capital program included $5,443,261 for the cost of designing and installing electrical distribution infrastructure required for new subdivisions and commercial areas under development in Oakville. Of this total, $1,043,129 was funded by Oakville Hydro and the remaining $4,400,132 was funded through capital contributions.

Road Widening – $1,105,334

Oakville Hydro Portion $651,136 – Contributed Capital $454,197

The 2012 capital program included $1,105,334 for the cost of relocating hydro facilities due to road widening work by the Town of Oakville, the Region of Halton and the Ministry of Transportation. Of this total, $651,136 was funded by Oakville Hydro and the remaining $454,197 was funded through capital contributions. These types of projects are non-discretionary.

System Renewal Projects - $7,571,478

As defined in the Chapter 5 Filing Requirements, projects in the System Renewal category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Oakville Hydro spent $7,571,478 on system renewal projects in 2012.

Load Transfer and System Security - $888,426

The 2012 capital program included $417,440 for the replacement of underslung switches at various locations in Oakville. 600A underslung porcelain switches were replaced with new polymer underslung switches to improve system reliability and efficiency.

Capital additions included $280,482 to upgrade Oakville Hydro's air-insulated switchgear. This is a multi-year program to replace existing PMH switchgear with new G&W gas-insulated switchgear which can be controlled automatically from Oakville Hydro's control room. Air insulated switchgear is subject to accelerated aging due to adverse weather conditions, road salt, etc. The gas insulated switchgear have a sealed tank compartment preventing the accelerated aging.

The 2012 capital program also included $155,797 for the upgrading and replacement of submersible transformer tops that were in poor condition. This is a multi-year program to eliminate existing rusting, damaged and corroding roof sections from the system. The replacement program improves safety and reduces outages. The new tops are constructed with galvanized coating and have a longer life expectancy.

Rebuild Overhead Distribution System - $2,454,789

The 2012 capital program included $2,454,789 for rebuilding the overhead distribution system.

As part of its Overhead Rebuild plan, Oakville Hydro replaced primary and secondary overhead wires, cable terminations and transformers that were assessed to be unsafe or non-compliant with standards, at a cost of $594,405. Completion of these projects improved reliability and enhanced safety while reducing future maintenance costs.

The 2012 capital program included $387,696 for the replacement of aging overhead pole lines throughout the distribution system. A description of Oakville Hydro’s pole replacement program is provided in the 2010 capital program section.

The 2012 capital additions included $1,276,059 to rebuild, replace and re-route pole lines that were installed in the rear of residential properties to safer, more accessible areas. This expenditure was part of a multi-year Rear Lot Distribution replacement project, planned to be completed in 2013.

Rebuild Underground Distribution System - $2,245,090

The 2012 capital program included $2,245,090 for rebuilding the underground distribution infrastructure.

The capital program included $944,742 for continuing the rebuild of the primary underground distribution system in the Holton Heights area (commenced in 2011), and $155,521 for a similar rebuild in the Sloane and Sunset Drive area. $184,431 was spent on underground rebuilds in various areas and involved the installation of duct and new cable to improve system reliability.

Capital additions included $190,027 to replace non-vented 28kV transformer bushing inserts and elbows throughout various areas in Oakville as identified through inspections by the Operations department.

The underground rebuild program also included $738,691 for the continuation of a multi-year program initiated in 2005 to eliminate Poletrans. Poletrans are streetlight poles with embedded transformers. These were installed between 1965 and 1971 and have safety and operational problems. In addition, replacement parts are not readily available. This project included cable replacement, new pad-mounted transformers and improved safety and reliability.

Substations - $643,618

In 2011, Oakville Hydro owned 20 municipal substations, the purpose of which is to step down the power from the four Hydro One owned transformer stations located at the four corners of Oakville as well as the Oakville Hydro owned Glenorchy Municipal Transformer Station that supplies North Oakville.

These municipal substations receive power from the transformer station feeders at 27.6kV, and step it down to either 4kV or 13.8kV. The power is then distributed to residential and commercial customers in South Oakville, through Oakville Hydro's distribution network. Most of the substations were built between 1950 and 1970. Oakville Hydro is continuously upgrading its substations. In 2010 the circuit breakers were replaced at the Cross St and Margaret municipal substations and in 2011 the transformer was replaced at the Sunset municipal substation.

In 2012, $643,618 was spent on substation equipment replacements and retrofits. This included the replacement of breakers, protection and supervisory equipment at the Munn's Municipal Substation for $591,398. The existing switchgear was low voltage 13.8kV, and only had one other station for backup. The breakers that were at the station were past end of life and had experienced significant mechanical wear. In addition, the protection and supervisory systems were replaced. This project continued Oakville Hydro's reinvestment in substation equipment and delivered fixed mounted breakers with modern Intelligent Electronic Device ("IED") protective relaying and integrated supervisory control capable of detailed fault monitoring and analysis.

Supervisory Control and Communications - $272,846

The System Renewal portion of the 2012 capital spend for supervisory control and communications was $272,846. This was for the continuation of a multi-year program to upgrade remote terminal units. The remote terminal units are subject to harsh weather conditions and have an average life span of 15 years. The units replaced in 2012 were past end of life.

Transformer Replacement and Voltage Conversion - $1,066,708

The 2012 capital program included $1,066,708 for transformer replacements and voltage conversion. Capital additions included $476,538 for the installation of new overhead/underground transformers in various locations throughout Oakville.

Capital additions included $197,865 to replace Delta transformers which were at end of life and for which replacement parts are not readily available. On average these units were 50 years old. This is a multi-year program and Oakville Hydro plans to phase these transformers out over time. The expenditure covered all costs to replace these units including pole upgrades and circuit additions as required.

The 2012 capital program included $277,017 for spare transformers in inventory, which were reclassified to fixed assets as per Board guidelines.

System Service Projects - $11,312,688

Projects in the category are driven by Oakville Hydro's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Oakville Hydro spent $11,312,688 on system service projects in 2012.

27.6kV Additions - $322,926

Capital additions included $322,926 to replace remote controlled switches. This was part of an ongoing program to upgrade older switches with more efficient and reliable units.

Administration – Information Technology - $775,928

Information Technology for System Service included $775,928 for upgrades to the SCADA and Outage Management System ("OMS") systems. 2012 expenditures for SCADA and OMS included a third party communication study for $37K. This study was initiated in 2010 with the purpose of:

- Performing and documenting a more thorough assessment of the existing communications infrastructure in terms of performance, reliability, and security
- Collaborating with the SCADA vendor to optimize their software for efficient and reliable wireless communication
- Identifying possible technical IT applications that will require telecom infrastructure
- Performing a high level investigation and evaluation of utility-grade communication solutions
- Supplying recommendations for development of a long-term communication strategy

Also included was substation communication to SCADA for $92,000. This project was initiated in 2010 and involves replacing the existing copper phone lines with fibre infrastructure. The existing copper phone lines were prone to failure and were time consuming to troubleshoot with the telecommunications carrier. The new fibre infrastructure included installation of a managed switch in each substation, and provisioning to extend the Corporate LAN, Phone System, and a security system out to each substation as required.

Capital additions also included $105,000 for SCADA Communications. In 2012, Oakville Hydro engaged a third party, Costello Associates, to document the status of the SCADA Communication Review Project that was initiated in the summer of 2010. After extensive staff testing and technical review by staff and Costello Associates, Oakville Hydro moved forward with implementation of GE MDS SD-4 radios. Oakville Hydro replaced the existing Analog radio system used for SCADA data with a Digital radio system. The existing Analog 400 MHz radio system serviced controllable distribution switches mainly in the north-east area of Oakville's service territory, communicating on what is essentially a voice radio system technology. This radio system was at the end of useful life, and required replacement. A new Digital 400 MHz radio system intended for communicating operational data directly replaced the existing analog 400 MHz system, reusing the existing licensed frequencies and repeater tower equipment.

In 2012, capital additions for vehicle communications were $85,000. Similar to the SCADA Communications, all of Oakville Hydro's vehicles were using a 400 MHz analog radio system at end of life. This system was prone to radio failure and was difficult to keep operational. This analog radio system was replaced with a Digital radio system that improved reliability and provided operational enhancements such as vehicle GPS location, digital display to show which vehicle was responding, an emergency 'mayday' button and future capability for call recording.

Capital additions for SCADA and OMS also included the replacement of the wall board in the Control Room for $383,000. This project was initiated in 2011, when the existing SCADA wall board display was at end of life, and did not have enough resolution for the operators to see the full system map when required for a load transfer. Due to this limitation, a static wall-sized white board, with colored tape and magnets, is used to track system status. A fully electronic SCADA system display maximizes efficiency both in normal switching operations, and in the event of power interruptions, in order to ensure safe operation of the overall system. Once coupled with the ability to display GIS information on the same display, it will be the operator's most useful daily tool. In addition, switches that are remotely-controllable and fault indicators that communicate back to the Control Room will be displayed. Both GIS and SCADA provide critical operational data which is displayed in real time on this new wall board, enabling timely, safety-focused, and efficient decision making.

The 2012 capital program included a SCADA Upgrade for $37,000. These costs related to a SCADA interface upgrade to the SmartVU platform that leverages the tools available in the current Windows platform to provide improved data visualization and enhanced functionality for OMS.

Lastly, the SCADA and OMS capital additions included the early stage development of an OMS system for $36,000. This project was initiated in 2010, when Oakville Hydro started a joint development project with Survalent (Oakville Hydro's SCADA system vendor) to be the initial Ontario LDC to develop, test and implement a new Outage Management System (OMS) as part of its SCADA system platform. This OMS system is going into live operation in late 2013.

The OMS software draws on information from the existing Harris-Customer Information Systems (CIS), Sensus-Advanced Metering Infrastructure (AMI), and ESRI-GIS platforms as a powerful tool for the Control Room operators to use when responding to system outages of any magnitude. This drives more efficient use of resources and faster restoration times for all distribution system interruptions. In addition, it allows for improved communications on status of outages to our customers and key stakeholders.

The OMS system is capable of handling call entry either using a call display interface or Interactive Voice Response (IVR) system to save time for the operator in taking input from affected customers. Once this information is combined with outage data from the AMI, the system recommends outage cases with the predicted fault locations allowing the operator to dispatch crews to these key locations to investigate.

The training time for this particular OMS system is minimized because it is integrated directly into the existing SCADA graphical interface that the operator is already familiar with. This system also captures outage information to help drive more accurate and thorough outage reporting for further system analysis and optimization.

The OMS software is a new subsystem within the Survalent Windows SCADA package. It is designed to run on the SCADA host computers, with a user interface built into the WorldView operator interface. The OMS therefore takes advantage of the existing hardware redundancy associated with the rest of the SCADA system.

Distribution Meters/Wholesale Meter Upgrades - $10,118,954

The majority of the 2012 the increase in capital spending for System Service Projects was due to the capitalization of Smart Metering costs in 2012. Oakville Hydro completed the deployment of Smart Meters in 2011. Detailed information on Oakville Hydro's Smart Meter project is in Oakville Hydro's Smart Meter Recovery Application (EB-2012-0193). The estimated capital cost of the Smart Meter program in the application was $10,331,152.

Supervisory Control and Communications - $94,880

The 2012 capital program included $94,880 to replace remote fault indicators. Newly installed fault indicators report back to Oakville Hydro's Control Room when a fault is detected which expedites identification of the issue and location. Increased ability to identify fault location has resulted in faster response and restoration times.

General Plant Projects - $2,022,334

Projects in this category are driven by Oakville Hydro's evolving requirements for capital to support day to day business and operations activities. Oakville Hydro spent $2,022,334 on General Plant projects in 2012.

Buildings - $261,256

The 2012 capital program included $106,192 for the expansion of the parking lot at Redwood Square, Oakville Hydro's head office. The existing parking lot did not have enough capacity to accommodate Oakville Hydro staff. $70,222 was also spent to reorganize the storage yard, also located at Redwood Square.

Information Technology - $811,937

The 2012 capital plan included $811,937 for computer hardware and software.

The 2012 capital program for computer hardware and software included $262,610 for Asset Management. In 2012, Oakville Hydro began a multi-year implementation of an Asset Management System ("AMS"). AMS comprises the tools used to execute the Asset Management Process. One component of the AMS - the Computerized Maintenance Management System ("CMMS") was initiated in 2012. The CMMS will contain a record of all patrols and maintenance activities performed on a piece of equipment. Optimal scheduling of patrols, maintenance and replacements will be streamlined with the acquisition and implementation of a CMMS. Maximo (by IBM) was selected and is being implemented to satisfy the CMMS requirement. Implementation of stage 1 began in 2012 and is expected to be completed by Q1 of 2014.

The implementation of a CMMS will also facilitate the completion of an overall asset record. This overall record contains four parts:

- The location of the asset is in the GIS system, which contains all information regarding the location and connectivity of the asset.
- The financial information would be in the Great Plains (GP) system, and contains information such as purchase price, total maintenance costs, and depreciated value.
- The equipment information would be in an equipment database, and would contain information such as nameplate specifications, or original approvals of the piece of equipment.
- The last piece of information, maintenance, would be contained in the CMMS, and would hold information regarding the maintenance on the equipment with the ability to perform trending to identify deteriorating assets. CMMS is required to link all the asset records together.

The 2012 capital program for computer hardware and software included $188,862 for the continued conversion of Oakville Hydro's GIS, a multi-year project that began in 2010.

Mobile GIS - With the distribution network in GIS, opportunities to share data with and provide information to field crews became available. The GIS system provides electronic information to field crews, previously provided on paper. The system allows access to information about the network that was not previously available in the field. It is anticipated that providing mobile access will improve productivity and accuracy in the areas of construction, maintenance, inspection and asset condition assessments. Workflow and communications will also be improved, particularly between Engineering & Operations.

- *Joint Use (Third Party Attachment) Reconciliation & Process Review* - The joint use review was required to inventory and accurately reflect the actual number of attachments in the field. The purpose of the review was to maximize the amount Oakville Hydro is collecting for attachment fees. The existing permits were reconciled with the GIS asset record and updated as required. The permit process was also reviewed, updated and automated. This improved processing time and accuracy, and allowed for easy retrieval of documents.

- *ESRI Version Upgrade* - A version upgrade was necessary to keep the software current and provide enhanced features and tools. Certain functions, not previously available to GIS users, were available with the upgrade, resulting in an increase in productivity, quality and accuracy.

The 2012 capital program for computer hardware and software also included $215,256 for Infrastructure including $111,107 for Microsoft Licenses and Software Assurance and $52,768 for security. This project was to enhance Oakville Hydro's initiatives in Cyber security. AESI Engineering and Management Consultants worked with Oakville Hydro to provide increased security measures in firewall and cyber access. Redundancy firewalls were put into place at Oakville Hydro's disaster recovery site.

The 2012 capital program included $78,195 for GP and Business Excellence enhancements, a multi-year project that began in 2010. The goals were to:

- achieve improvement in material forecasting
- reduce inventory levels in the warehouse
- improve the efficiencies within the warehouse

- increase job/project material availability in order to improve overall efficiency

Processes were standardized and system solutions were planned for 2012 to support these initiatives. The most notable one that is currently in motion is the Quadra Solution (ERTH Corporation) – joint development is currently underway with ERTH to develop and roll out a two-phase Project Estimating / Material Forecast application linked to Great Plains (Wennsoft). The first phased was completed in 2011. The second phase (with greater GP/Wennsoft integration and project / program scheduling) began in 2012. The tangible benefits of this new will be easier project cost estimation, more accurate material forecasts and ability to plan and manage the Construction program.

Also included in the 2012 capital program was $67,014 for Customer Service Initiatives including a Harris SQL upgrade.

Major Tools and Safety Equipment - $109,329

The 2012 capital program included $109,329 for tools required to perform work safely in line operations, the protection and control department and the meter department.

Fleet - $839,811

The 2012 capital program included $839,811 to replace aging vehicles. This included replacement of one Double Bucket truck at a cost of $449,337 (2000 -12 years old), one Single Bucket truck at a cost of $288,697 (2004 - 8 years old), and a Service Body truck at a cost of $101,777.

2013 Capital Additions

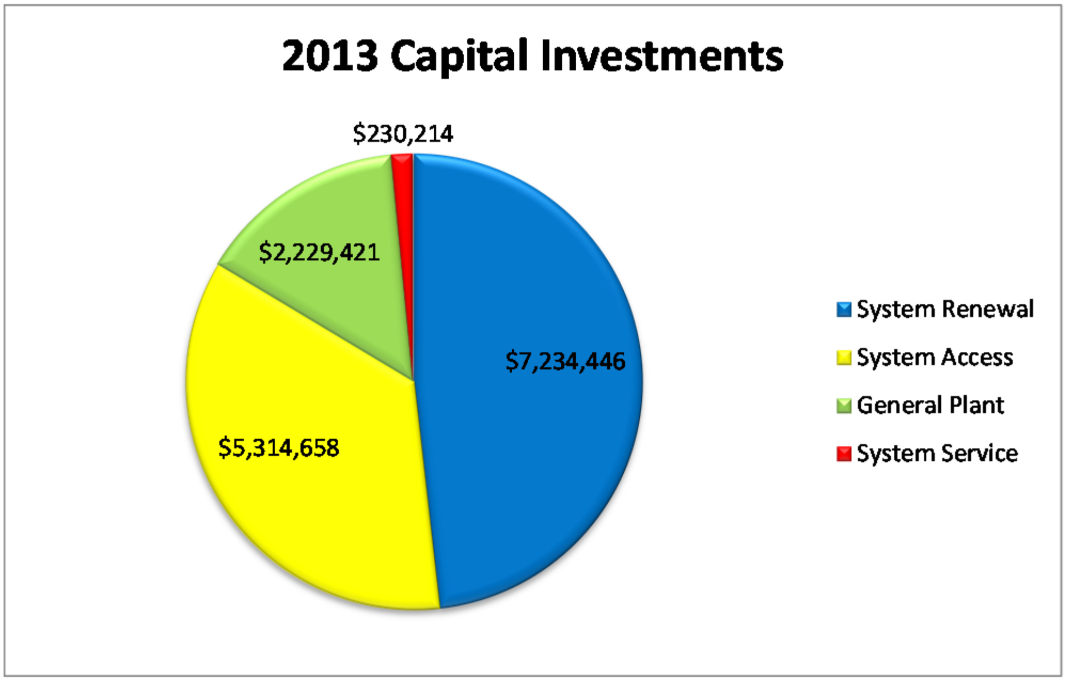
Chapter 5 of the Filing Requirements sets out the Investment Categories for grouping capital investments according to the driver of the expenditure. Table 2-42, 2013 Capital Investments, provides a breakdown of forecasted capital spending for the 2013 Bridge Year in accordance with the Board's Investment Categories.

Table 2-42 - 2013 Capital Projects - Total

Major Project	2013 Old CGAAP	2013 New CGAAP
27.6kV Additions	$1,879,441	$1,333,282
Distribution Meters / Wholesale Meter Upgrades	479,202	362,879
New Development / Services	1,412,561	1,102,130
Road Widening (Dependent on Road Work - No Hydro Control)	1,543,453	1,023,557
System Access	**5,314,658**	**3,821,848**
Alterations and Improvements for Load Transfer and System Security	572,150	471,194
Rebuild Overhead Distribution System	2,466,663	1,874,389
Rebuild Underground Distribution System	2,299,891	1,714,853
Substations	930,273	782,606
Supervisory Control and Communications	144,088	105,869
Transformer Replacements and Voltage Conversion	821,381	585,917
System Renewal	**7,234,446**	**5,534,829**
Administration - IT	45,000	45,000
Distribution Meters / Wholesale Meter Upgrades	77,000	77,000
Supervisory Control and Communications	108,214	79,443
System Service	**230,214**	**201,443**
Administration - Buildings	72,500	66,046
Administration - IT	1,403,474	1,379,477
Major Tools and Safety Equipment	115,439	107,902
Fleet	638,008	583,203
General Plant	**2,229,421**	**2,136,627**
Grand Total	**$15,008,738**	**$11,694,747**

Oakville Hydro's capital additions for 2013 in Old CGAAP are forecasted to be $15,008,738, a decrease of $8,987,735 versus 2012. 2012 included the capitalization of Smart Meters of $10,118,954 and additional spending of $162,960 for the Glenorchy Municipal Transformer

Station. All figures for 2013 are stated on an Old CGAAP basis unless indicated otherwise. The following graph illustrates the breakout of each of the Investment Categories.



When compared with 2012 capital additions excluding the Glenorchy Municipal Transformer Station and smart meters, spending is expected to increase by $1,290,568 versus 2012. Year over year spending is fairly consistent across System Renewal and General Plant projects. System Access for 2013 has increased $2,384,034 over 2012 as 2013 projects include the construction of feeders to service the new Oakville Hospital and feeders for Milton Hydro (as an embedded distributor). System Service has decreased by $963,521 versus 2012 as 2012 included a significant investment in SCADA and OMS.

The New CGAAP equivalent of the 2013 Old CGAAP additions is $11,694,747, a decrease of $3,313,991. This difference is due to a change in Oakville Hydro's capitalization policy, specifically the removal of certain burdens from capital under New CGAAP which were previously capitalized under Old CGAAP. Refer to Exhibit 2, Tab 6 for more details on Oakville Hydro's change to its capitalization policy.

Similar to historical years, 2013 projects have been categorized into System Access, System Renewal, System Service and General Plant as per the Chapter 5 Consolidated Distribution System Plan Filing Requirements issued by the Board on March 28, 2013.

System Access Projects - $5,314,658 (Old CGAAP); $3,821,848 (New CGAAP)

Projects in the System Access category are driven by statutory, regulatory or other obligations on the part of Oakville Hydro to provide customers with access to the distribution system. Oakville Hydro plans to spend $5,314,658 ($3,821,848 – New CGAAP) on system access projects in 2013.

27.6kV Additions - $1,879,441 (Old CGAAP); $1,333,282 (New CGAAP)

The 2013 capital program includes $1,257,319 to add a new feeder in order to supply the new hospital being constructed at Dundas and Third Line. The new feeder will span Neyagawa Blvd, from Burnhamthorpe Rd to Dundas St W, and Dundas St W from Neyagawa Blvd. to Third Line. The work will be completed in conjunction with a proposed road widening on Neyagawa Blvd. Also included in 27.6kV additions is $551,840 for the addition of two new feeders to supply Milton Hydro with power from the Glenorchy TS.

Distribution Meters/Wholesale Meter Upgrades - $479,202 (Old CGAAP); $362,879 (New CGAAP)

The 2013 capital program includes $402,202 for the installation of meters to comply with industry standards. The capital program also includes $77,000 for an upgrade to the Regional Network interface for smart metering.

New Development/Services - $4,910,711 (Old CGAAP); $3,891,935 (New CGAAP)

Oakville Hydro Portion CGAAP $1,412,561 – Contributed Capital CGAAP $3,498,150

The 2013 capital program includes $4,910,711 for the cost of designing and installing electrical distribution infrastructure required for new subdivisions and commercial areas under development in Oakville. Of this total, $1,412,561 is expected to be funded by Oakville Hydro and the remaining $3,498,150 funded through capital contributions.

Road Widening – $2,334,308 (Old CGAAP); $1,548,831 (New CGAAP)

Oakville Hydro Portion $1,543,453 – Contributed Capital $790,855

The 2013 capital program includes $2,334,308 for the cost of relocating hydro facilities due to road widening work by the Town of Oakville, the Region of Halton and the Ministry of Transportation. Of this total, $1,543,453 is expected to be funded by Oakville Hydro and the remaining $790,855 funded through capital contributions. These types of projects are non-discretionary.

System Renewal Projects - $7,234,446 (Old CGAAP); $5,534,829 (New CGAAP)

As defined in the Chapter 5 Filing Requirements , projects in the System Renewal category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Oakville Hydro plans to spend $7,234,446 ($5,534,829 – New CGAAP) on system renewal projects in 2013.

Load Transfer and System Security - $572,150 (Old CGAAP); $471,194 (New CGAAP)

The 2013 capital program includes $395,863 to upgrade Oakville Hydro's air-insulated switchgear. This is a multi-year program to replace existing PMH switchgear with new G&W

gas-insulated switchgear which can be controlled automatically from Oakville Hydro's control room. Air insulated switchgear is subject to accelerated aging due to adverse weather conditions, road salt, etc. On average, from 2009 to 2013, over four failures per year were experienced on air insulated switchgear. In addition, the average outages caused by flashovers occurring in air insulated switch gear were twelve per year. The gas insulated switchgear have a sealed tank compartment preventing the accelerated aging.

Rebuild Overhead Distribution System - $2,246,663 (Old CGAAP); $1,874,389 (New CGAAP)

The 2013 capital program includes $2,246,663 for rebuilding the overhead distribution system.

As part of its Overhead Rebuild plan, Oakville Hydro plans to replace primary and secondary overhead wires, cable terminations and transformers that are unsafe or non-compliant with standards, at a cost of $240,000. Completion of these projects will improve reliability and enhance safety while reducing future maintenance costs.

The 2013 capital program includes $174,005 for the replacement of aging overhead pole lines throughout the distribution system. A description of Oakville Hydro's pole replacement program is provided in the 2010 capital program section.

Also included is $1,978,269 to rebuild, replace and re-route pole lines that were installed in the rear of residential properties to safer, more accessible areas. This expenditure is part of a multi-year Rear Lot Distribution replacement project, and is expected to be completed in 2013.

Rebuild Underground Distribution System - $2,299,891 (Old CGAAP); $1,714,853 (New CGAAP)

The 2013 capital program includes $2,299,891 for rebuilding the underground distribution infrastructure.

The capital program includes $809,697 for continuing the rebuild of the primary underground distribution system in the Holton Heights area (commenced in 2011 and expected to be completed in 2013). Capital additions of $583,585 and $116,276 are expected for underground rebuilds on Speers Road and McCraney Street respectively. These projects involve the installation of duct and new cable to improve system reliability.

Capital additions of $207,511 are expected to be incurred to replace non-vented 28kV transformer bushing inserts and elbows throughout various areas in Oakville as identified through inspections by the Operations department. This replacement program also addresses safety and operational issues.

The underground rebuild program also includes $555,875 for the continuation of a multi-year program initiated in 2005 to eliminate Poletrans. This program is expected to be completed in 2014. Poletrans are streetlight poles with embedded transformers. These were installed between 1965 and 1971 and have safety and operational problems. In addition, replacement parts are not readily available. This project includes cable replacement, new pad-mounted transformers and improves safety and reliability.

Substations - $930,273 (Old CGAAP); $782,606 (New CGAAP)

Oakville Hydro currently owns 20 municipal substations, the purpose of which is to step down the power from the four Hydro One owned transformer stations located at the four corners of Oakville as well as the Oakville Hydro owned Glenorchy Municipal Transformer Station that supplies North Oakville.

These municipal substations receive power from the transformer station feeders at 27.6kV, and step it down to either 4kV or 13.8kV. The power is then distributed to residential and commercial customers in South Oakville, through Oakville Hydro's distribution network. Most of the substations were built between 1950 and 1970. Oakville Hydro is continuously upgrading its substations, with circuit breaker replacements (Cross St., Margaret, Munn's), transformer replacements (Sunset) and protection and supervisory equipment replacements (Munn's) taking place over the last three years.

In 2013, $930,273 is expected to be spent on substation equipment replacements and retrofits.

This includes the replacement of low voltage breakers at the Sunset MS for $335,000. This is part of a multi-year project to replace breaker equipment in municipal substations to avoid the risks associated with the failure of municipal substation breaker equipment. Oakville Hydro's municipal substations supply anywhere from 500 to 2000 customers, and in the event of a switchgear failure these customers may need to be transferred to other substations, which would be challenging to achieve during the summer peak load season, and would require extensive manual field operation and coordination.

Also included is $288,000 for the planned replacement of the power transformer at the Albion municipal substation. Without a proactive replacement program for these transformers, Oakville Hydro could expect to spend over $300,000 to replace a failed unit after an unexpected failure. The timelines to replace when failure occurs would be extensive, putting risk on the rest of the distribution system. There is potential for large extensive outages until either the transformer is replaced, or the load on the feeders can be properly distributed to adjacent feeders.

The remaining expenditures are for substation equipment refurbishment and upgrades.

Supervisory Control and Communications - $144,088 (Old CGAAP); $105,869 (New CGAAP)

The System Renewal portion of the 2013 capital spend for supervisory control and communications is expected to be $144,088. This is for the continuation of a multi-year program to upgrade remote terminal units. The remote terminal units are subject to harsh weather conditions and have an average life span of 15 years. The units to be replaced in 2013 are at end of life.

Transformer Replacements and Voltage Conversion - $821,381 (Old CGAAP); $585,917 (New CGAAP)

The 2013 capital program includes $821,381 for transformer replacements and voltage conversion.

Included in this program is $226,786 for the voltage conversion of the 4kV system on First Street, south of Lakeshore Road East. The distribution system in this area is aging and in need of rebuilding. Since this area represents a small pocket of 4kV distribution the intent is to convert the system to 27.6kV.

Capital expenditures of $139,564 are planned for the completion of the decommissioning of the Allan Street municipal substation, begun in 2011. Some of the substation components experienced failure and the age of the assets was beyond end of useful life. Some loads will be converted to 27.6kV distribution and others will be redistributed to other stations.

Capital expenditures of $150,886 are expected to be incurred to replace Delta transformers which have no straight replacement stock available. On average these units are 50 years old. This is the second year of a multi-year program and Oakville Hydro plans to phase these transformers out over time. The planned expenditure covers all costs to replace these units including pole upgrades and circuit additions if required.

Capital expenditures of $179,143 are planned for the installation of new overhead/underground transformers in various locations throughout Oakville.

System Service Projects - $230,214 (Old CGAAP); $201,443 (New CGAAP)

Projects in the category are driven by Oakville Hydro's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Oakville Hydro plans to spend $230,214 on system service projects in 2013.

Supervisory Control and Communications - $108,214 (Old CGAAP); $79,443 (New CGAAP)

The 2013 capital program includes $50,000 to replace remote fault indicators. Newly installed fault indicators report back to Oakville Hydro's control room when a fault is detected which expedites identification of the issue. Increased ability to identify fault location has resulted in faster response and restoration times.

Capital expenditures of $50,000 are also planned for repeater site upgrades required at the common communication repeater site for Oakville Hydro's voice and RTU communication systems.

General Plant Projects - $2,229,421 (Old CGAAP); $2,136,627 (New CGAAP)

Projects in this category are driven by Oakville Hydro's evolving requirements for capital to support day to day business and operations activities. Oakville Hydro expects to spend $2,229,421 on General Plant projects in 2013.

Buildings - $72,500 (Old CGAAP); $66,046 (New CGAAP)

Capital expenditures of $55,000 are planned to remove existing and install new chain-link fencing at six substations (Pinegrove, Cross, Thomas, Sheridan, Industry, Albion) due to degradation and deterioration.

The 2012 capital program also includes $17,500 to convert all exterior building neon signage/lighting to LED (Oakville Hydro logo only - total three signs). The original neon signs are 19 years old and require ongoing repair and maintenance. Old neon technology will be replaced with energy efficient LED.

Information Technology - $1,403,474 (Old CGAAP); $1,379,477 (New CGAAP)

The 2013 capital plan includes $1,403,474 for computer hardware and software. This includes $393,500 for Infrastructure including but not limited to:

- Back-up/Storage Solution $80,000
- Desktop and laptop replacements $76,500

- Disaster Recovery $60,000
- Infrastructure Enhancements $60,000
- Printers $40,000

The capital program for computer hardware and software includes $262,000 for the conversion and evolution of Oakville Hydro's Geographic Information System (GIS) including:

- Pole Stability and Loading Software $30,000 – this software is required to perform proper and accurate non-linear analysis required for pole line designs. This tool will also increase the productivity and accuracy of designs being prepared for construction crews.

- Local circuit re-drafting $152,000 – the existing GIS network was drawn using multi-phase conductors to streamline the first GIS network implementation. Now that Oakville Hydro is working to integrate the GIS network with the OMS, these multi-phase conductors need to be expanded into multiple single phase conductors to enable the network export tool to convert the topological GIS network into a logic network that is required for OMS.

Capital expenditures of $342,500 are planned for GP and Business Excellence enhancements including but not limited to:

- New Budgeting, Forecasting and Reporting software $152,000 – Oakville Hydro is currently using Forecaster and FRx by Microsoft. Forecaster has several deficiencies; most notably it does not handle Balance Sheets and Cash Flows efficiently. Microsoft has announced that it will not continue support for either platform. In addition, Oakville Hydro has experienced errors with the software that internal and external consulting services could not remedy.
    - Workplace Requisition software $75,500
    - Quadra Phase II and SOP to Order $65,000 – this project is discussed further in the 2012 Capital Section

Capital expenditures of $110,000 are budgeted for Asset Management. This includes $80,000 for Phase 2 of the implementation of Maximo, a software application used to manage and track the status of distribution assets, including the scheduling of patrols, maintenance and replacements. This initiative is discussed in further detail in the 2012 Capital Section.

Capital expenditures of $110,000 are budgeted for Customer Service Initiatives including an upgrade to Harris version 6.4 and Customer Connect software. This software is part of the Harris application and improves customer service by allowing customers to request services on line and access their personal data and billing information. In 2012 Oakville Hydro launched a project to map its Meter to Cash ("M2C") processes to identify gaps and opportunities for improvement. Several initiatives, listed below were identified.

- Customer Connect (eCare replacement)
- Collection software for Final Bills
- Five Key Business Initiatives Developed
    - Reduction In Write-Offs
    - Faster Meter To Cash Cycle
    - Reduce Truck Rolls
    - Process Automation and Process Management
    - Reduce/Eliminate Third Party Contracts

Oakville Hydro determined that increased functionality is required in the Meter Data Management / Operational Data Store (ODS) system to address identified gaps. Oakville Hydro has initiated an ODS working group to start planning the implementation of these functionalities, and identify possible gaps associated with associated internal IT systems. Oakville Hydro plans to continue to invest in Customer Service Initiatives beyond 2013 to better serve customers and achieve continuous improvement in productivity and cost performance.

Major Tools and Safety Equipment - $115,439 (Old CGAAP); $107,902 (New CGAAP)

The 2013 capital program includes $115,439 for tools (new and replacement) required to perform work safely in Line Operations, the protection and control department and the meter department.

Fleet - $638,008 (Old CGAAP); $583,203 (New CGAAP)

The 2013 capital program includes $638,008 to replace aging fleet assets. This includes the replacement of a 38ft Single Bucket Hybrid at a cost of $216,394 and the replacement of a Hybrid Aerial Device for $356,000.

2014 Capital Additions

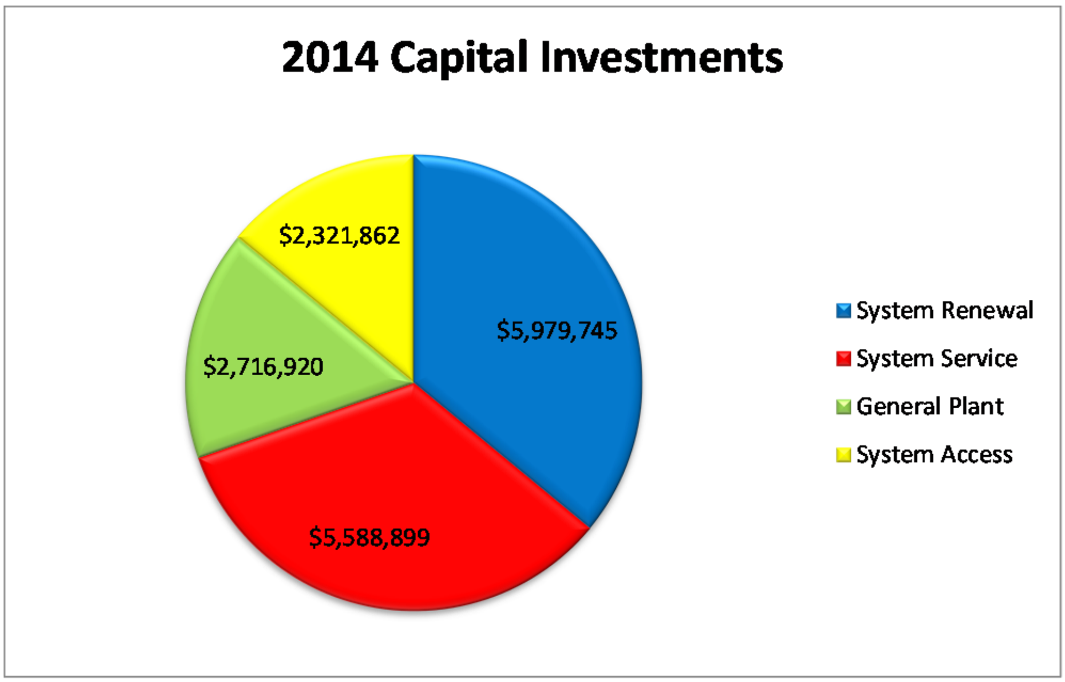
Chapter 5 of the Filing Requirements sets out the Investment Categories for grouping capital investments according to the driver of the expenditure. Table 2-43, 2014 Capital Investments, provides a breakdown of forecasted capital spending for the 2013 Bridge Year in accordance with the Board's Investment Categories.

Table 2-43 - 2014 Capital Investments

Major Project	New CGAAP	New CGAAP ex Emergency TX and 3rd Party IRU
27.6kV Additions	$420,973	$420,973
Distribution Meters / Wholesale Meter Upgrades	$481,706	$481,706
New Development / Services	$1,016,068	$1,016,068
Road Widening (Dependent on Road Work - No Hydro Control)	$403,115	$403,115
System Access	**$2,321,862**	**$2,321,862**
Alterations and Improvements for Load Transfer and System Security	$1,028,655	$1,028,655
Rebuild Overhead Distribution System	$1,118,877	$1,118,877
Rebuild Underground Distribution System	$2,017,232	$2,017,232
Substations	$1,016,763	$1,016,763
Supervisory Control and Communications	$231,887	$231,887
Transformer Replacements and Voltage Conversion	$566,332	$566,332
System Renewal	**$5,979,745**	**$5,979,745**
Administration - IT	$452,000	$452,000
Rebuild Overhead Distribution System	$100,000	$100,000
Supervisory Control and Communications	$36,899	$36,899
Transformer Replacements and Voltage Conversion	$5,000,000	$0
System Service	**$5,588,899**	**$588,899**
Administration - Buildings	$341,615	$341,615
Administration - IT	$1,897,210	$1,159,000
Major Tools and Safety Equipment	$93,333	$93,333
Fleet	$384,762	$384,762
General Plant	**$2,716,920**	**$1,978,710**
Grand Total	**$16,607,427**	**$10,869,217**

Oakville Hydro's capital additions for 2014 are forecasted to be $16,607,427 (New CGAAP), an increase of $4,912,680 versus the 2013 Bridge Year. The capital expenditures for the 2014 Test

Year include the purchase of an on-site emergency back-up transformer for the Glenorchy Municipal Transformer Station of $5,000,000 and an adjustment in the value of a capital lease between Oakville Hydro and a third party for fibre optic cables of $738,210. This adjustment is discussed in further detail in Exhibit 2, Tab 2, Schedule 5. The on-site back-up emergency transformer is discussed in more detail in the DS Plan. All figures for 2014 are stated on a New CGAAP basis unless indicated otherwise. The following graph illustrates the breakout of each of the Investment Categories.



When compared with 2013 capital additions excluding the on-site emergency back-up transformer and the 3rd party IRU adjustment, spending is expected to decrease by $825,530 versus the 2013 budget, with lower spending in the system access category, partially offset by increased spending in system renewal and system service.

In 2013, system access projects include the construction of feeders to service the new Oakville Hospital and feeders for Milton Hydro, and embedded distributor, at a cost of $1,272,167. There are $420,973 of 27.6kV additions required for system access in 2014.

In the System Renewal category, expenditures in Load Transfer and System Security and Substations are expected to increase in 2014, partly offset by a decrease in rebuilds for the overhead distribution system. Load Transfer and System Security includes a new project - the replacement of 27.6kV vacuum gang operated switches with new SCADAmate loadbreak switches. Substation expenditures include the replacement of low voltage breakers at the Victoria MS for $547,715 which have been in service since 1973. The decrease in rebuilds for the overhead distribution system are due to the completion of the multi-year Rear Lot Distribution replacement project in 2013, part of Oakville Hydro's overhead rebuild program. Expenditures for this program averaged $1.5M (Old CGAAP) per year since 2008.

In the System Service category, spending is expected to increase by $387,455 over 2013 due to higher spending on SCADA and OMS.

Similar to historical years, 2014 projects have been categorized into System Access, System Renewal, System Service and General Plant as per the Chapter 5 Consolidated Distribution System Plan Filing Requirements issued by the Board on March 28, 2013.

Oakville Hydro has created templates for 2014 capital projects over the materiality threshold of $190,000 for System Access, System Renewal, System Service and General Plant projects. These are filed in this Exhibit as part of the DSP. These templates provide general information, evaluation criteria and category specific requirements as required in the Chapter 5 Consolidated DS Plan Filing Requirements.

System Access Projects - $2,321,862

Projects in the System Access category are driven by statutory, regulatory or other obligations on the part of Oakville Hydro to provide customers with access to the distribution system. Oakville Hydro plans to spend $2,321,862 on system access projects in 2014.

27.6kV Additions - $420,973

The 2014 capital program includes $420,973 for an additional 27.6kV feeder on Upper Middle Road from Ninth Line to Highway 403, to support load growth in the Winston Business Park.

Distribution Meters/Wholesale Meter Upgrades - $481,706

The 2014 capital program includes $481,706 for the installation of residential meters, commercial meters, dial-up upgrades, and a new Tower Gateway Base Station ("TGB").

New Development/Services - $4,087,834

Oakville Hydro Portion $1,016,068– Contributed Capital CGAAP $3,071,766

The 2014 capital program includes $4,087,334 for the cost of designing and installing electrical distribution infrastructure required for new subdivisions and commercial areas under development in Oakville. Of this total, $1,016,068 is expected to be funded by Oakville Hydro and the remaining $3,071,766 is funded through capital contributions.

Road Widening – $630,630

Oakville Hydro Portion $403,115 – Contributed Capital $227,515

The 2014 capital program includes $630,630 for the cost of relocating hydro facilities due to road widening work by the Town of Oakville, the Region of Halton and the Ministry of Transportation. Of this total, $403,115 is expected to be funded by Oakville Hydro and the remaining $227,515 funded through capital contributions. These figures are lower than 2013 as road widening projects are expected to somewhat decrease from historical levels due to an anticipated decline in municipal, regional and provincial projects. These types of projects are non-discretionary.

System Renewal Projects - $5,979,745

As defined in the Chapter 5 Filing Requirements , projects in the System Renewal category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure"). Oakville Hydro plans to spend $5,979,745 on system renewal projects in 2014.

Load Transfer and System Security - $1,028,655

The 2014 capital program includes $379,340 to upgrade Oakville Hydro's air-insulated switchgear. This is a multi-year program to replace existing PMH switchgear with new G&W gas-insulated switchgear which can be controlled automatically from Oakville Hydro's control room. Air insulated switchgear is subject to accelerated aging due to adverse weather conditions, road salt, etc. The gas insulated switchgear have a sealed tank compartment preventing the accelerated aging.

Also included in the 2014 capital program is $267,139 to replace 27.6kV Vacuum gang-operated switches in the distribution system. This will cover the cost to replace five switch locations with new SCADAmate loadbreak switches. These switches can fail without warning, and there is no maintenance that can be performed in order to keep them in working order. Spare parts for these switches are not available.

Rebuild Overhead Distribution System - $1,118,877

The 2014 capital program includes $1,118,877 for rebuilding the overhead distribution system.

As part of its Overhead Rebuild plan, Oakville Hydro plans to replace primary and secondary overhead wires, cable terminations and transformers that are unsafe or non-compliant with standards, at a cost of $566,189. Completion of these projects will improve reliability and enhanced safety while reducing future maintenance costs.

Oakville Hydro plans to replace the overhead assets on Robinson Street between Navy St. and Allan St. at a cost of $458,981. Primary and secondary distribution system assets at this location are at end of life and were found to be in poor condition during the 2010 overhead patrol.

The 2014 capital program includes $68,744 for the replacement of aging overhead pole lines throughout the distribution system. Expenditures for this program have decreased year over year as the majority of poles have been replaced and have a useful life of 45 years. A description of Oakville Hydro's pole replacement program is provided in the 2010 capital program section.

2014 expenditures on overhead rebuilds have decreased versus prior years as the Rear Lot Distribution replacement project is expected to be completed in 2013.

Rebuild Underground Distribution System - $2,017,232

The 2014 capital program includes $2,017,232 for rebuilding the underground distribution infrastructure.

The capital program includes $1,161,796 for rebuilding the primary underground distribution system in various areas of Oakville. These projects involve the installation of duct and new cable to improve system reliability.

Oakville Hydro expects to incur $126,011 to replace non-vented 28kV transformer bushing inserts and elbows throughout various areas in Oakville as identified through inspections by the Operations department. This improves safety while operating and maintaining these assets.

The underground rebuild program also includes $316,241 to replace "live front" vault transformers and current limiting fuses in vault rooms. This expenditure of $316,241 represents the costs associated with the first year of a proposed multi-year project to eliminate this type of transformer from Oakville Hydro's system due to access and operation issues. The average age of these assets is 38 years old.

The underground rebuild program also includes $292,164 for the continuation of a multi-year program initiated in 2005 to eliminate Poletrans. This program is expected to be completed in

2014. Poletrans are streetlight poles with embedded transformers. These were installed between 1965 and 1971 and have safety and operational problems. In addition, replacement parts are not readily available. This project includes cable replacement, new pad-mounted transformers and improves safety and reliability.

Substations - $1,016,763

In 2014 Oakville Hydro will own 19 municipal substations, the purpose of which is to step down the power from the four Hydro One-owned transformer stations located at the four corners of Oakville as well as the Oakville Hydro-owned Glenorchy Municipal transformer station that supplies North Oakville.

These municipal substations receive power from the transformer station feeders at 27.6kV, and step it down to either 4kV or 13.8kV. The power is then distributed to residential and commercial customers in South Oakville, through Oakville Hydro's distribution network. Most of the substations were built between 1950 and 1970. Oakville Hydro is continuously upgrading its substations, with significant replacements for circuit breakers, transformers and protection and supervisory equipment taking place over the last four years at various substations.

In 2014, $1,016,763 is expected to be spent on substation equipment replacements and retrofits.

This includes the replacement of low voltage breakers at the Victoria MS for $547,715 which have been in service since 1973. The replacement of the breakers at Victoria MS will take place in 2014. This is part of a multi-year project to replace breaker equipment in municipal substations to avoid the risks associated with the failure of municipal substation breaker equipment. Oakville Hydro's municipal substations supply anywhere from 500 to 2000 customers, and in the event of a switchgear failure these customers may need to be transferred to other substations, which would be challenging to achieve during the summer peak load season, and would require extensive manual field operation and coordination.

Also included is $268,190 for the planned replacement of the power transformer at the Woodhaven municipal substation which is the oldest power transformer in Oakville Hydro's distribution system and has been in service since 1957. Without a proactive replacement program for these transformers, Oakville Hydro could expect to spend over $300,000 to replace a failed unit after an unexpected failure. There is potential for large extensive outages until either the transformer is replaced, or the load on the feeders can be properly distributed to adjacent feeders.

The remaining expenditures are for substation equipment refurbishment and upgrades.

Supervisory Control and Communications - $231,887

The System Renewal portion of the 2014 capital spend for supervisory control and communications is expected to be $231,887.

The 2014 capital program includes $105,815 for the continuation of a multi-year program to upgrade remote terminal units. The remote terminal units are subject to harsh weather conditions and have an average life span of 15 years. The units to be replaced in 2014 are at end of life.

Also included is $126,073 for a dTechs MeterSuite pilot project initiated in 2012. dTechs offers metering solutions which enable electric utilities to monitor their entire distribution grid. The dTechs MeterSuite is an advanced wireless metering system created to help utilities directly address grid management, line-loss reduction and power theft. The system will enable Oakville Hydro to increase its ability to detect, monitor and control technical and non-technical energy losses on a quarter of Oakville Hydro's distribution system. Oakville Hydro's Smart Grid strategy is filed in this Exhibit as part of the DSP. This project is one of those approved within the Ministry of Energy's ("MOE") Smart Grid Fund (Phase One).

Transformer Replacements and Voltage Conversion - $566,332

The 2014 capital program includes $566,332 for transformer replacements and voltage conversion.

Included in this program is $275,730 to replace the remaining "live front" padmount transformers in Oakville Hydro's distribution territory. Oakville Hydro has phased these transformers out over time and only a handful remains in the field with no straight replacement stock available. On average these units are 40 years old and beyond their Typical Useful Life. This budget represents year one of the program and covers the cost of all cable replacements and pole upgrades. The distribution system in these areas is need of rebuilding and will be converted from 4kV to 27.6kV.

$172,171 is expected to be incurred to replace Delta transformers which have no straight replacement stock available. On average these units are 50 years old and beyond their Typical Useful Life. This is the second year of a multi-year program and Oakville Hydro plans to phase these transformers out over time. The planned expenditure covers all costs to replace these units including pole upgrades and circuit additions if required.

Capital expenditures of $118,430 are planned for the installation of new overhead/underground transformers in various locations throughout Oakville.

System Service Projects - $5,588,899

Projects in this category are driven by Oakville Hydro's expectations that evolving customer use of the distribution system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives. Oakville Hydro plans to spend $5,588,899 on system service projects in 2014.

Information & Technology - $452,000

This 2014 capital program includes $452,000 for upgrades to the SCADA and OMS systems including $300,000 for SCADA enhancements in Loadflow, Contingency Analysis and Fault Detection Isolation Restoration ("FDIR"). These enhancements are expected to result in process improvements in the Control Room that drive optimized system configuration and improved outage restoral. Existing operational risks associated with feeder loading and equipment operation will be mitigated.

2014 capital expenditures also include $152,000 for CYME, a power system analysis software tool that will be linked to the GIS for network information, the AMI for loading data, and Maximo for asset information. CYME will be used to supply the following capabilities that are Utility Best Practice but not readily available at Oakville Hydro: system load studies to establish system capacity utilization, transformer loading studies for asset utilization, system fault level studies to validate equipment ratings, and phase balance studies to optimize system configuration and reduce technical losses.

Rebuild Overhead Distribution System - $100,000

The 2014 capital program includes $100,000 for a Solar Integration Project. This project is discussed in further detail in the DS Plan.

Supervisory Control and Communications - $36,899

The 2014 capital program includes $36,899 to replace remote fault indicators. Newly installed fault indicators report back to Oakville Hydro's control room when a fault is detected which expedites identification of the issue. Increased ability to identify fault location has resulted in faster response and restoration times.

Transformer Replacements and Voltage Conversion - $5,000,000

$5,000,000 has been budgeted for an on-site emergency back-up transformer for the Glenorchy Municipal Transformer Station ("Glenorchy MTS"). The Glenorchy Municipal Transformer Station does not have an emergency back-up transformer in event of a failure. In order to minimize risk of disruption to customers, it is imperative and critical to have an emergency back-up transformer. The rationale and alternatives for this project are discussed in detail in Oakville Hydro's DS Plan in Appendix A to this Exhibit.

General Plant Projects – $2,716,920

Projects in this category are driven by Oakville Hydro's evolving requirements for capital to support day to day business and operations activities. Oakville Hydro expects to spend $2,716,920 on General Plant projects in 2014.

Buildings - $341,615

The 2014 capital program includes $209,524 for the replacement of HVAC and mechanical equipment in 2014. Approximately 85 units will be replaced over a five year period. Oakville Hydro is experiencing more frequent breakdowns, requiring replacement and/or costly repair, in particular with units that are rooftop and exposed to the elements. Lead time for replacement units on an emergency basis varies from 4-10 weeks depending on type. Repair costs on these aging units continue to increase. Newer technology will result in more energy efficient products, improved operations, improved reliability and decreased maintenance costs.

Also included in the 2014 capital program is $54,658 for Security System Upgrades to three of Oakville Hydro's municipal substations (Bronte, Devon and Sunset). Costs include the installation of hardware and configuration of Siemens software to monitor substations for security and fire. This will improve security and provide on-demand visual control from the Control Room and Security Control Room.

Capital expenditures include $40,083 for full asphalt replacement of the upper parking lot at Redwood Square including directional and parking re-lining. The area is approximately 15,500 square feet.

Information Technology - $1,897,210

The 2014 capital plan includes $738,210 for an adjustment to the value of a capital lease between Oakville Hydro and a third party for optical fibres. This adjustment is discussed in detail in Exhibit 2, Tab 2, Schedule 5. The remaining $1,159,000 of the $1,897,210 Administration IT capital plan is for computer hardware and software.

The 2014 capital program for computer hardware and software includes $420,000 for Infrastructure. This is made up of the following:

- Substation Foundry Switches $80,000
- Server Replacement $60,000
- Incremental Storage $60,000
- Desktop and laptop replacements $50,000
- Network Infrastructure $50,000
- Mobile Security $50,000
- Microsoft Licenses and Software Assurance $40,000
- Plotter/Scanner Upgrade $30,000

Capital expenditures include $150,000 for the continued conversion and evolution of Oakville Hydro's GIS as follows:

- Conduit Manager - a software enhancement to GIS that will allow accurate tracking of cables within Oakville Hydro's duct and manhole system. Oakville Hydro maintains complex duct and manhole systems in the Downtown, Kerr/Speers, Bronte, Uptown Core and North Oakville areas. Accurate and easy to access records are essential for efficient operations and maintenance in these areas.

Capital expenditures of $203,000 are planned for GP and Business Excellence Enhancements including $123,000 for the Microsoft Dynamic GP Upgrade to GP2013 and $80,000 for Business Intelligence and Data Management.

Capital expenditures of $100,000 are budgeted for Asset Management for Phase 3 of the implementation of Maximo, a software application used to manage and track the status of distribution assets, including the scheduling of patrols, maintenance and replacements. This initiative is discussed in further detail in the 2012 capital section.

The 2014 capital program includes $210,000 for Customer Service Initiatives including an Interactive Voice Response System (“IVR”) for $150,000, on-line applications for customer service for $15,000, meter reading improvements for $25,000 and data access for $20,000. An IVR allows customers to interact with Oakville Hydro’s Customer Information System (CIS) via a telephone keypad or by speech recognition, after which they can service their own inquiries by following the IVR dialogue. Oakville Hydro’s goal is to provide customers with the ability to access their information on the phone via voice prompts and have access to their account details and data, in addition to the development of improved tools for communicating outage information. Further information on these projects is provided in Appendix A as part of the DSP.

Major Tools and Safety Equipment - $93,333

The 2014 capital program includes $93,333 for tools (new and replacement) required to perform work safely in line operations, the protection and control department and the meter department.

Fleet - $384,762

The 2014 capital program includes $384,762 to replace aging vehicles. This includes the replacement of a 1991 propane powered forklift, a roadway operations support vehicle, four pickup trucks, a van and a 2004 car for the Engineering Department.

Capitalization Policy

Oakville Hydro's capitalization policies and principles are based on Canadian Generally Accepted Accounting Principles ("CGAAP"), and guidelines set out by the Ontario Energy Board, where applicable. Effective January 1st, 2013 Oakville Hydro's capitalization policy will conform to International Financial Reporting Standards (IFRS).

Property, plant and equipment ("PP&E") include expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour and other costs directly attributable to bringing the asset to a working condition for its intended use.

- Assets with a cost in excess of $1,000 expected to provide future economic benefit greater than one year will be capitalized.
- Expenditures that create a physical betterment or improvement of an asset will be capitalized.
- With respect to transportation equipment all costs associated with placing a vehicle into service are capitalized.
- Computer software that is acquired or developed by Oakville Hydro will be capitalized and classified as an intangible asset

Guidelines For Capitalization

Capital Assets

Capital Assets include property, plant, and equipment that are held for use in the production or supply of goods and services and provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. Intangible assets are also considered capital assets and are defined as assets that lack physical substance. They include goodwill, patents, copyrights and computer software.

Betterment

A "betterment" is a cost which enhances the service potential of a capital asset and/or increases its value, and is therefore capitalized. A betterment includes expenditures which increase the capacity of the asset, lower associated operating costs of the asset, improve the quality of output or extend the asset's useful life. A betterment does not include general maintenance-related actions that seek to sustain an asset's current value. An example of a betterment would be injection of fluid into existing underground cables, which is warrantied to extend the life of those cables for an additional 40 years.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and are charged to an operating account.

Capital Asset Cost

Cost

Cost is the amount of consideration to acquire, construct, develop or better a capital asset. The cost of an item of property, plant and equipment includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Pre-construction and start-up costs including feasibility studies and planning/design activities which occur before the project has been approved are specifically excluded from capitalization as they cannot be attributed to a specific item of property, plant and equipment at the time they are incurred.

Examples of directly attributable costs are:

a) Materials directly used in the asset
b) Costs of employee benefits (as defined in IAS 19 Employee Benefits) directly attributable to construction or acquisition of the asset
c) Costs of site preparation
d) Direct delivery and handling costs
e) Installation and assembly costs
f) Costs of testing whether the asset is functioning properly
g) Professional fees directly attributable to the asset.

Examples of costs that are not costs of an item of PP&E are:

a) Costs of opening a new facility (including feasibility studies)
b) Costs of introducing a new product or service (including feasibility studies)
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training)
d) Administration and general overhead cost
e) Costs of relocating or reorganizing
f) Abnormal waste

Recognition of costs in the carrying amount of an item of property, plant and equipment ceases when the item is in the location and condition necessary for it to be capable of operating in the manner intended by management.

Capitalization by Component

When parts or components of an item of property, plant and equipment have different useful lives, they are accounted for as individual items (major components) of property, plant and equipment.

Component costs must be significant in relation to the total cost of the item and depreciated separately over the component's useful life. Components are those which:

- Are significant in relation to the total cost of the item
- Have different depreciation methods or useful life

Components with similar useful lives and depreciation methods are grouped in determining the depreciation charge. Parts of the item that are not individually significant (remainder of the items) are combined and categorized as a single component best suited for the sum of the parts.

Oakville Hydro has identified the 39 components listed in Table 2-44, Capital Components, into which items of property plant and equipment would be classified.

1 ## Table 2-44 – Capital Components

Component	OEB Code	Description	Typical Useful Life
01OHS	1830	OH Pole System	45
02OHD	1835	OH Devices	45
03OHM	1835	OH Local Motorized/Remote Automated Switches	25
04OHW	1835	OH Wires	60
05TRN	1850	Distribution Transformers	35
06UGS	1840	Duct & Civil ex Metal	50
07UGM	1840	Metal Frames & Covers	30
08UGG	1845	Pad Mounted Switch Gear	30
09UGC	1845	UG Cable System	35
10MSE	1820	Substation Equipment	25
11MSS	1820	MS Main Switch Gear	55
12MST	1850	MS Transformers	45
13SCD	1980	System Supervisory Equipment	15
14TSE	1820	TS Substation Equipment	30
15TSS	1820	TS Switchgear	50
16TST	1815	TS Transformer	45
17MTD	1860	Meters	25
18MTS	1860	Smart Meters	10
19MTI	1860	Smart Meters - Infrastructure	10
20SDC	1855	UG Services - Duct & Civil	50
21SUG	1855	UG Services - Cable	35
24CHP	1920	Computer Hardware - PCs	3
25CHN	1920	Computer Hardware - Servers	4
26CHC	1920	Computer Hardware - Infrastructure	4
27CSC	1925	Computer Software - Client	4
28CSI	1925	Computer Software - Infrastructure	4
29CSA	1925	Computer Software - Business Apps	5
30OFF	1915	Office equipment	10
31SAF	1960	Safety Equipment	10
32BLD	1808	Buildings	60
33BLL	2005	Capital Lease - Building	Life of lease
34LND	1805	Land	n/a
38LHI	1810	Leasehold Improvements	10
39WHE	1935	Warehouse Equipment	10
40TLS	1940	Major Tools	7
41VHP	1930	Vehicles - Passenger	5
42VHT	1930	Vehicles - Light & Heavy	10
43VHO	1930	Vehicles - Other Mobile Equipment	10
44LMS	1970	Load Management	20

2

Depreciation

Depreciation is recognized on a straight-line basis over the estimated useful life of each significant identifiable component of an item of property, plant and equipment. Land is not depreciated. Construction in progress assets are not depreciated until the project is complete and in service.

Factors considered in determining estimated service life are:

- Replacement policy of the component and parts
- Age of existing components
- Manufacturer specifications
- Future plans to remove from service
- External and/or internal asset reviews

Depreciation of an asset begins in the year when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended. Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale and the date that the asset is derecognized. Depreciation does not cease when the asset becomes idle or is retired from active use unless the asset is fully depreciated.

In the first year of service, depreciation is calculated using the ½ year rule. Under this rule, capital assets additions are assumed to be put into service equally throughout the year, therefore, on average depreciation starts at the midpoint of the acquisition year.

Due to the change in estimate of the remaining useful life of many of the assets beginning in 2013, the net book value of capital assets as of December 31, 2012 is amortized over the remaining years of useful life of each component.

Capital Spares

Spare transformers and switch gear retained for emergency use are accounted for as capital assets since they form an integral and critical part of the reliability program for a distribution system. Emergency spares are necessary because of the lead-time required in the manufacture and delivery of transformers and switchgear. Emergency spares are depreciated in accordance with the depreciation policy of the items in use.

Changes to Capitalization Policy

Oakville Hydro has changed its capitalization policy since its last rebasing application. These changes are discussed in the next section "Capitalization of Overhead" and in Tab 6 of this Exhibit "Accounting Changes under CGAAP".

Capitalization of Overhead

As part of the transition to IFRS, and in accordance with the Board's requirements, Oakville Hydro has reviewed its overhead costs to determine which continue to be appropriate directly attributable expenses to capitalize and which should be expensed as part of Operating Maintenance and Administration costs. Oakville Hydro determined the following burdens are directly attributable to PP&E and should therefore be capitalized:

Labour Burden

The labour burden rate will consist of a direct benefit burden only and will be reduced from 108% to 30% to reflect the removal of the following:

- apprenticeship training and non-productive time which cannot be directly attributed to a specific job
- administration burden of 50% which recovered management time and General and Administrative costs of Engineering and Operations

The revised benefit burden of 30% recovers the employment benefits that employees are entitled to receive such as CPP, EI, medical and dental benefits, OMERS, EHT and WSIB. This burden is applied to hourly labour cost by specific job at 30% and is therefore directly attributable to an item of PP&E at the time the cost is incurred.

Vehicle Charges

With respect to repairs and maintenance, IFRS states that the costs of day-to-day servicing of an item of PP&E cannot be recognized in the carrying amount. These costs are expensed as incurred. Therefore the vehicle charge to capital only includes fuel and consumables.

Table 2-45, Summary of Changes to Burdens, provides a summary of the change in burden rates from Oakville Hydro's Old CGAAP to New CGAAP effective January 1, 2013. Accounting changes under CGAAP and capitalization of overhead are discussed in more detail in Exhibit 2, Tab 6.

Table 2-45– Summary of Changes to Burdens

Burden	Old CGAAP	New CGAAP Effective January 1, 2013
Labour	108% of hourly cost • Direct benefits 22% (CPP, EI, dental, medical, OMERS) • Unproductive time 36% (training, weather, vacation, bereavement time, sick time, union business etc.) • Administration burden 50% (Line Supervisor, P&C and engineering for oversight and project coordination)	30% of hourly cost • Direct benefit 30% (CPP, EI, dental, medical, OMERS, EHT, WSIB)
Direct materials	5% charge to cover purchasing and payment processing	Nil
Subcontractors	15% charge to cover purchasing, and payment processing and engineering and supervision of capital projects	Nil
Warehouse	18% charge to cover purchasing and payment processing, storage costs and warehouse operations	Nil
Fleet	Hourly rate based on an allocation of maintenance costs, fuel and consumables and depreciation of equipment	Hourly rate to include only fuel and consumables

Oakville Hydro has filed the table, Overhead Expense (Board Appendix 2-DB) to show the overhead costs on self-constructed assets that are currently capitalized under Old CGAAP and no longer capitalized under New CGAAP.

Appendix 2-DB
Overhead Expense

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 overhead costs that are currently capitalized on self-constructed assets under revised CGAAP or ASPE (with the changes in capitalization and depreciation expense policies).

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on PP&E Historic Year**	**Dollar Impact on PP&E Bridge Year**	**Dollar Impact on PP&E Test Year**	**Dollar Impact - PP&E Variance Test versus Bridge**	**Dollar Impact - PP&E Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are allowed to be capitalized under CGAAP or ASPE (with the changes in policies) given limitations on capitalized overhead**
employee benefits	$ 403,518	$ 459,143	$ 421,008	-$ 38,135	$ 17,491	Y	30% burden rate includes payroll costs and benefit programs
costs of site preparation				$ -	$ -		not applicable for 2013 and 2014 capital projects
initial delivery and handling costs				$ -	$ -		overhead costs for direct materials disallowed
costs of testing whether the asset is functioning properly				$ -	$ -		included in employee benefits
professional fees				$ -	$ -		not applicable for 2013 and 2014 capital projects
				$ -	$ -		
costs of opening a new facility				$ -	$ -		not applicable for 2013 and 2014 capital projects
costs of introducing a new product or service (including costs of advertising and promotional activities)				$ -	$ -		not applicable for 2013 and 2014 capital projects
costs of conducting business in a new location or with a new class of customer (including costs of staff training)				$ -	$ -		not applicable for 2013 and 2014 capital projects
administration and other general overhead costs	$ 68,428	$ 85,242	$ 70,999	-$ 14,242	$ 2,571	Y	vehicle fuel and consumables charged to asset hourly
				$ -	$ -		
				$ -	$ -		
				$ -	$ -		
Insert description of additional item(s) and new rows if needed.				$ -	$ -		
Total	$ 471,946	$ 544,385	$ 492,007	-$ 52,377	$ 20,061		

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 overhead costs that were capitalized on self-constructed assets under CGAAP but are no longer capitalized under revised CGAAP or ASPE (with the changes in capitalization and depreciation expense policies) and are included in OM&A.

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
Nature of the Overhead Costs	**Dollar Impact on OM&A Historic Year**	**Dollar Impact on OM&A Bridge Year**	**Dollar Impact on OM&A Test Year**	**Dollar Impact - OM&A Variance Test versus Bridge**	**Dollar Impact - OM&A Variance Test versus Historic**	**Directly Attributable? (Y/N)**	**Reasons why the overhead costs are allowed to be capitalized under CGAAP or ASPE (with the changes in policies) given limitations on capitalized overhead**
employee benefits	$ 376,616	$ 428,534	$ 392,941	-$ 35,593	$ 16,325	N	training and unproductive time disallowed
costs of site preparation				$ -	$ -		not applicable for 2013 and 2014 capital projects
initial delivery and handling costs	$ 15,966	$ 58,207	$ 250,504	$ 192,296	$ 234,538	N	5% burden on direct materials is for G&A costs ; $177K in 2014 relates to 5% burden on emergency back-up transformer
costs of testing whether the asset is functioning properly				$ -	$ -		included in employee benefits
professional fees				$ -	$ -		not applicable for 2013 and 2014 capital projects
costs of opening a new facility				$ -	$ -		not applicable for 2013 and 2014 capital projects
costs of introducing a new product or service (including costs of advertising and promotional				$ -	$ -		not applicable for 2013 and 2014 capital projects
costs of conducting business in a new location or with a new class of customer (including costs				$ -	$ -		not applicable for 2013 and 2014 capital projects
administration and other general overhead costs	$ 2,681,678	$ 2,475,393	$ 2,384,439	-$ 90,953	-$ 297,238	N	50% engineering burden for G&A costs, 18% material burden
				$ -	$ -		for warehouse and purchasing departments, 15%
				$ -	$ -		subcontractor burden for engineering and operations
				$ -	$ -		contracting and supervision, repairs and maintenance for
Insert description of additional item(s) and new rows if needed.				$ -	$ -		vehicles which are specifically disallowed under IFRS
Total	$ 3,074,260	$ 2,962,133	$ 3,027,884	$ 65,750	-$ 46,376		

Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

Oakville Hydro has not incurred any costs for the connection of qualifying generation facilities.

Addition of ICM Assets to Rate Base

In 2011, Oakville Hydro completed the construction of its Glenorchy Municipal Transformer Station in order to service the customers of Oakville. In its 2011 IRM application (EB-2010-0104), Oakville Hydro received approval for the recovery of the revenue requirement associated with the incremental capital costs associated with the design and construction of the Municipal Transformer Station. In its Decision and Order, the Board found that the capital costs incurred were prudent and that Oakville Hydro had provided adequate evidence that potential alternatives were analyzed and that the completion of the project represented the most cost effective alternative for ratepayers. Oakville Hydro began recovering its costs through an Incremental Capital Module ("ICM") Rate Rider which will expire on April 30, 2014. A photograph of the Glenorchy Municipal Transformer Station is provided below.

In its Decision and Order, the Board approved the forecasted costs of $21,360,209. However, actual total capital costs were higher than forecasted and Oakville Hydro incurred total costs of $22,860,578. Oakville Hydro has incorporated the total costs of $22,860,578 in its rate base as detailed in Table 2-46.

Table 2-46 – Glenorchy Municipal Transformer Station Capital Asset Amounts to be Incorporated in Rate Base

Description	2011	2012	2013	2014
Gross Fixed Assets	$22,860,578	$22,860,578	$22,860,578	$22,860,578
Accumulated Depreciation	(215,138)	(645,414)	(1,138,357)	(1,631,300)
Net Book Value	22,645,440	22,215,164	21,722,221	21,229,278
Average Net Book Value/Increase to Rate Base	**$11,322,720**	**$22,430,302**	**$21,657,314**	**$21,475,749**

Actual capital spending exceeded the Board-approved amount by $1,500,369. Oakville Hydro has provided a variance analysis in Table 2-47, with an explanation for any variances.

1 **Table 2-47 – Actual Capital Spending vs. Board Approved Amount**

Description	ICM Board Approved Amount	Actual Capital Spending to 2011	Actual Capital Spending vs. Board Approved Amount	Comments
Substation Equipment	$2,194,534	$2,631,576	$437,042	Field modifications and design revisions associated with discrepancies found during commissioning, and the addition of IT infrastructure for SCADA backup and disaster recovery
TS Switchgear - Gas	3,411,961	3,431,751	19,790	Additional time required for equipment testing & verification
TS Transformer	7,026,035	6,811,103	(214,932)	The complexity of field work associated with equipment testing & verification was lower than anticipated
Revenue Meters	502,584	482,221	(20,363)	Less time required for equipment testing & verification
SCADA & DC Systems	146,622	211,172	64,550	The work associated with operational verification of the SCADA system including integration with substation equipment required additional scope
UG Cable	283,476	521,198	237,722	The final cable lengths and per unit cost were higher than originally estimated
Duct & Civil	1,681,483	2,326,671	645,188	The ground water flows present on the site were much higher than the geotechnical survey predicted, increasing the cost and complexity of the duct & civil construction work
Building	4,395,414	4,856,462	461,048	The ground water flows present on the site were much higher than the geotechnical survey predicted, increasing the cost and complexity of the building foundation
Land	1,367,700	1,421,336	53,636	The final cost of land was higher than originally estimated
HV Commissioning	110,000	0	(110,000)	Commissioning costs have been allocated to the appropriate components, actual cost was $322,000
CCRA Capital Contribution	240,400	167,089	(73,311)	Hydro One's actual cost was lower than their budget estimate
Total	**$21,360,209**	**$22,860,578**	**$1,500,369**	

2

The main areas in which actual capital spending exceeded the Board-approved amount were in the Duct and Civil, Building, Substation Equipment and Underground Cable categories. Duct and Civil and Building expenditures exceeded the Board-approved amount by $1,106,235. This was largely due to the condition of the site location. Ground water flows were higher than the geotechnical survey predicted which impacted the cost of the access road, infrastructure and storm water management. Substation equipment exceeded the Board-approved amount by $437,042 due to field modifications, design revisions and IT infrastructure for SCADA backup and disaster recovery. Underground Cable was higher than the Board-approved amount by $237,722 as final cable length and per unit costs were higher than originally estimated. Overall, costs were also higher than anticipated due to inclement weather and equipment delays.

Oakville Hydro did not record any amounts related to the Glenorchy Municipal Transformer Station in Account 1508 Other Regulatory Assets, in accordance with direction received from Board staff. The rationale behind this direction was that the revenues and expenses associated with the ICM rate rider should be reflected in the P&L when earned/incurred to avoid a large impact to the revenue in one year. Therefore, Oakville Hydro has recorded revenue earned through its rate rider in USofA account 4080 Distribution Revenue and recorded its capital costs in the USofA account 1815 Transformer Station Equipment and depreciation in USofA account 5705 Depreciation Expense.

Table 2-48, Amounts to be Recorded in Account 1508, provides the amounts that would have been recorded in Account 1508 Other Regulatory Assets for May 1, 2011 to April 30, 2014.

Table 2-48 – Amounts to be Recorded in Account 1508

Account 1508 Other Regulatory Asset, Sub Account	2011	2012	2013	2014
Incremental Capital Expenditures	$22,860,578	$22,860,578	$22,860,578	$22,860,578
Depreciation Expense	$215,138	$430,276	$492,943	$492,943
Accumulated Depreciation	($215,138)	($645,414)	($1,138,357)	($1,631,300)
Incremental Capital Expenditures Rate Rider	$1,221,995	$1,871,603	$1,843,604	$612,391

Oakville Hydro is requesting the approval for the true up of the variances between actual capital spending and the Board approved amount in its ICM application (EB-2010-0104), net of any over recoveries from its approved ICM Rate Rider. Oakville Hydro has calculated the difference between its recalculated revenue requirement and the forecasted revenues to April 30, 2014 in Table 2-49, Recalculated Revenue Requirement. The recalculated revenue requirement of $5,834,937 is $285,343 higher than the rate rider revenues forecasted to be recovered from the customer of $5,549,594.

Table 2-49 – Recalculated Revenue Requirement

Description	Capital	Revenue Requirement	Total Revenue Requirement 2011 to 2014
Board Approved Amounts		**$1,818,850**	**$5,456,550**
Projected Over Recovery vs Board Approved Revenue Requirement		(24,755)	(93,044)
ICM Collected/To Be collected		**$1,843,604**	**$5,549,594**
Board Approved Amounts	**$21,360,209**	**$1,818,850**	**$5,456,550**
Variance Between Actual Capital Spending and Board Approved Amounts	1,500,369	126,129	378,387
Recalculated Amounts	**$22,860,578**	**$1,944,979**	**$5,834,937**
Variance Recalculated Revenue Requirement vs. ICM Collected - Due from/(Owed to Customer)			**$285,343**

Oakville Hydro proposes that the shortfall of $285,343 be recovered from customers through a volumetric rate rider over one year. The calculation of this incremental capital expenditures rate rider is detailed in Table 2-50.

Table 2-50 – Proposed Incremental Capital Expenditures Rate Rider

Customer Class	2012 Actual kWh	2012 Actual kW	Allocation % Based on kWh	Allocated Balance	Recovery Period (Years)	Unit	Rate Rider
Residential	602,407,699	-	39.05%	$111,430	1	$/kWh	$0.0002
General Service < 50 kW	166,851,635	-	10.8%	30,863	1	$/kWh	$0.0002
General Service > 50 to 999 kW	607,509,364	1,647,015	39.4%	112,373	1	$/kW	$0.0682
General Service > 1000 kW	150,201,768	332,469	9.7%	27,783	1	$/kW	$0.0836
Unmetered Loads	3,696,824	-	0.2%	684	1	$/kWh	$0.0002
Sentinel Lights	120,534	335	0.0%	22	1	$/kW	$0.0666
Street lights	11,824,926	32,927	0.8%	2,187	1	$/kW	$0.0664
Total	**1,542,612,750**	**2,012,745**	100.0%	**$285,343**			

Service Quality and Reliability Performance

Oakville Hydro tracks service reliability statistics System Average Interruption Duration Index (“SAIDI”), System Average Interruption Frequency Index (“SAIFI”), and Customer Average Interruption Duration Index (“CAIDI”) including and excluding loss of supply-related incidents and reports these to the Board on an annual basis. Oakville Hydro’s performance is within the range of acceptable performance over the previous five years and no corrective action is required. Table 2-51, Service Reliability Indicators below summarizes the service reliability indicators for the last five years (2008-2012). The Board’s Appendix 2-G is also provided in this Exhibit.

Table 2-51 - Service Reliability Indicators

Year	SAIDI	SAIFI	CAIDI
	Hours	Interruptions/ Customer	Hours
Including Loss of Supply			
2008	1.54	1.60	0.96
2009	0.77	1.57	0.49
2010	0.74	1.15	0.65
2011	0.47	1.04	0.45
2012	0.81	0.97	0.84
5 Years Rolling Average	**0.87**	**1.27**	**0.68**
Excluding Loss of Supply			
2008	1.21	1.28	0.94
2009	0.77	1.57	0.49
2010	0.73	1.08	0.68
2011	0.46	1.01	0.46
2012	0.81	0.97	0.84
5 Year Rolling Average	**0.80**	**1.18**	**0.68**

In addition to the reliability indices, Oakville Hydro also measured and tracked service quality indicators (“SQIs”) in the period from 2008 to 2012. Oakville Hydro’s performance has been better than the Board’s objectives for these indicators and no corrective action is required. Table 2-52 summarizes Oakville Hydro’s results for the last five years.

Table 2-52 - Reported Service Quality Indicators (SQIs)

Indicator	*Minimum Standard*	*2008*	*2009*	*2010*	*2011*	*2012*	*Average*
Connection of New Services – Low Voltage	90% or better	96.6%	97.2%	95.0%	95.4%	96.6%	96.2%
Connection of New Services – High Voltage	90% or better	N/A	N/A	N/A	N/A	N/A	N/A
Appointments - Scheduled	90% or better	100.0%	100.0%	100.0%	100%	100.0%	100.0%
Appointments - Met	90% or better	100.0%	99.9%	93.7%	100%	100.0%	98.7%
Rescheduling a missed appointment	100%	100.0%	100.0%	100.0%	100%	100.0%	100.0%
Telephone Accessibility	65% or better	81.4%	74.7%	86.2%	81.1%	83.7%	81.4%
Telephone Call Abandon Rate	less than 10%	N/A	5.3%	1.4%	2%	1.6%	2.5%
Written Responses to Inquiries	80% or better	100.0%	99.0%	98.7%	100%	100.0%	99.4%
Emergency Response – Urban Areas	80% or better	N/A	N/A	N/A	N/A	100.0%	N/A
Emergency Response – Rural Areas	80% or better	N/A	N/A	N/A	N/A	N/A	N/A

Appendix 2-G
Service Reliability Indicators
2008 - 2012

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2008	2009	2010	2011	2012	2008	2009	2010	2011	2012
SAIDI	1.540	0.773	0.745	0.467	0.811	1.206	0.773	0.734	0.465	0.811
SAIFI	1.603	1.571	1.152	1.042	0.967	1.284	1.571	1.079	1.006	0.967

5 Year Historical Average

SAIDI		0.867		0.798
SAIFI		1.267		1.181

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Accounting Changes Under CGAAP

Background

On February 13, 2008, the Canadian Accounting Standards Board ("AcSB") officially confirmed the requirement for publicly accountable enterprises to adopt International Financial Reporting Standards (IFRS) for financial reporting purposes in 2011. IFRS is a set of accounting standards developed by the International Accounting Standards Board (IASB) that is becoming the global standard for the preparation of public company financial statements. By adopting IFRS, a business can present its financial statements on the same basis as its foreign competitors, making comparisons easier. Furthermore, companies with subsidiaries in countries that require or permit IFRS may be able to use one accounting language company-wide.

However, the concept of regulatory accounting is not considered under the current IFRS framework or in any specific standard. Consequently, items which were previously reported as regulatory assets and liabilities under CGAAP do not meet the current definition of assets and liabilities under IFRS and are reported as income or expense in the period in which the transaction occurred.

In July 2009, the IASB issued an Exposure Draft ("ED") proposing accounting requirements for rate-regulated activities ("RRA"). In September 2010, the IASB staff issued Agenda Paper 12 outlining the staff's view that regulatory assets and regulatory liabilities did not meet the definitions of an intangible asset under IAS 38 – Intangible Assets, a financial liability nor a provision under IAS 37 – Provisions, Contingent Liabilities and Contingent Assets.

The Canadian Electricity Association ("CEA") wrote a joint letter to the IASB on September 2010 requesting that an interim standard to grandfather previous GAAP accounting practices, such as those in Canada, be developed with respect to accounting for regulatory assets and liabilities.

The IASB response indicated that it would further consider an interim standard after public consultation.

On April 26, 2013, the IASB published for public comment *the Exposure Draft: Regulatory Deferral Accounts* as part of its reactivated Rate-regulated Activities research. The exposure draft was open for comments until September 4, 2013. The Exposure Draft proposes an interim Standard which would allow entities to preserve the existing accounting policies that they have in place for rate-regulated activities with some modifications designed to enhance comparability. These interim measures would remain in place until guidance is developed through the IASB's comprehensive Rate-regulated Activities project. This project will consider whether the IASB should develop specific guidance for Rate-regulated Activities and, if so, what information about the consequences of rate regulation would be most useful for users of financial statements.

IFRS Implementation Deferrals

This potential for further discussions with respect to rate regulated accounting resulted in the AcSB providing four separate one year extensions:

In October 2010, the AcSB approved the incorporation of a one year deferral of Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specifies that first-time adoption is mandatory for interim and annual financial statements relating to annual periods beginning on or after January 1, 2012.

- In March 2012, the AcSB decided to extend the deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by one more year, from 2012 to 2013.Rate-regulated entities had the option to defer their changeover to IFRS to January 1,2013.
- In September 2012, the AcSB decided to extend the deferral by an additional year to January 1, 2014 and in February 2013, an extension to January 1, 2015 was granted.
- The additional deferral date to January 1, 2015 was in light of discussions at the IASB indicating that it expects to issue an interim standard by the end of 2013.

The deferral decision in March 2012 prompted the Board to release a statement on April 30, 2012 indicating that the Board will not require regulatory accounting and reporting for 2012 to be in Modified IFRS ("MIFRS" = IFRS modified to accommodate rate regulated entities) if a distributor is not required to adopt IFRS for financial reporting and opts to remain on CGAAP. (Board Letter, April 30, 2012 "*Impact of the Decision to Defer the Mandatory Date for the Implementation of International Financial Reporting Standards to January 1, 2013 by the Canadian Accounting Standards Board*").

Subsequent to this statement the Board received numerous requests from distributors for regulatory accounting direction to make changes to depreciation rates and capitalization polices while still under CGAAP, as the work had already been completed during the transition to IFRS.

On July 17, 2012 the Board issued a statement that changes to depreciation rates and capitalization policies that would have been implemented under IFRS could be made in 2012 under CGAAP (i.e. effective January 1, 2012), and must be made no later than 2013 (i.e. effective January 1, 2013), regardless of whether the AcSB permits further deferrals beyond 2012 for the changeover to IFRS. (Board Letter, July 17, 2012 "*Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013*").

Oakville Hydro's Decision and Cost of Service Application

Oakville Hydro decided to take advantage of the deferral of the implementation of IFRS either until a final AcSB standard was prepared and required, or until it was required to make changes in order to minimize the complexity of the transition and consequently the cost. In accordance with the Board's guidelines published July 17, 2012, Oakville Hydro implemented changes to its depreciation rates and capitalization policy effective January 1, 2013. These CGAAP statements, modified for the new depreciation rates and capitalization policy, will be referred to as New CGAAP.

The following section provides a summary of Oakville Hydro's accounting changes to depreciation rates and capitalization policy and a summary of calculated Rate Base and Base Revenue Requirement for the 2013 Bridge Year and the proposed 2014 Test Year in accordance with New CGAAP. The difference between amounts calculated under New CGAAP in comparison to those calculated in accordance with Old CGAAP is also provided.

New Policies and Differences between CGAAP and IFRS

Componentization and Depreciation

Under IFRS, specifically under International Accounting Standard ("IAS") 16, each significant part of an item of PP&E must be depreciated separately. This is referred to as component accounting. The rationale for component accounting is that since not all components of an item of PP&E have the same useful life, they will depreciate at different rates.

The Board requested that the utilities have third party analysis to support the development of components and useful lives. Consequently, in 2009, in preparation for the original (before deferral) conversion to IFRS, Oakville Hydro contracted Kinectrics to perform an analysis of the useful lives of its distribution assets in conjunction with Enersource Corporation, Milton Hydro Distribution Inc., Burlington Hydro Electric Inc. and Halton Hills Hydro Inc. A group of representatives from the Engineering, Purchasing and Finance departments of each of the utilities met to determine the components of their distribution assets and provided these to Kinectrics. Kinectrics performed analysis and recommended a range for the useful life of each component. Since each utility in the group does not use exactly the same products in the construction of their assets, each utility proposed slightly different useful lives, but typically they fell within the range of useful lives as recommended by Kinectrics. Subsequent to Oakville Hydro's review and analysis the Board commissioned Kinectrics to perform an industry-wide review. This report was received December 10, 2009.

Based on these Kinectrics reports, Oakville Hydro broke down its PP&E into 39 components. Oakville Hydro's components and useful lives are set out in Table 2-53. These have been verified by Oakville Hydro's Engineering department and Senior Management, both of which have agreed that the useful lives are reasonable for the assets in Oakville Hydro's distribution system. A copy of the Kinectrics report prepared for Oakville Hydro is provided as Appendix B in this Exhibit.

Table 2-53 – Oakville Hydro's Components and Useful Lives

Component	OEB Code	Description	Old CGAAP Useful Life	Kinectrics Range (Board Report)	Kinectrics Typical Useful Life (Board Report)	New CGAAP Useful Life
01OHS	1830	OH Pole System	25	35-75	45	45
02OHD	1835	OH Devices	25	30-60	45	45
03OHM	1835	OH Local Motorized/Remote Automated Switches	25	15-25	20-25	25
04OHW	1835	OH Wires	25	50-75	60	60
05TRN	1850	Distribution Transformers	25	25-60	35-40	35
06UGS	1840	Duct & Civil ex Metal	25	30-85	50-60	50
07UGM	1840	Metal Frames & Covers	25	20-45	30	30
08UGG	1845	Pad Mounted Switch Gear	25	20-45	30	30
09UGC	1845	UG Cable System	25	25-55	30-40	35
10MSE	1820	Substation Equipment	30	10-65	20-55	25
11MSS	1820	MS Main Switch Gear	30	30-60	40-50	55
12MST	1850	MS Transformers	25	30-60	45	45
13SCD	1980	System Supervisory Equipment	15	10-65	20-45	15
14TSE	1820	TS Substation Equipment	25	10-65	20-55	30
15TSS	1820	TS Switchgear	25	30-60	40-50	50
16TST	1815	TS Transformer	50	30-60	45	45
17MTD	1860	Meters	25	15-35	n/a	25
18MTS	1860	Smart Meters	25	5-15	n/a	10
19MTI	1860	Smart Meters - Infrastructure	25	10-20	n/a	10
20SDC	1855	UG Services - Duct & Civil	25	30-85	50-60	50
21SUG	1855	UG Services - Cable	25	25-60	35-40	35
24CHP	1920	Computer Hardware - PCs	3	3-5	n/a	3
25CHN	1920	Computer Hardware - Servers	3	3-5	n/a	4
26CHC	1920	Computer Hardware - Infrastructure	3	3-5	n/a	4
27CSC	1925	Computer Software - Client	5	2-5	n/a	4
28CSI	1925	Computer Software - Infrastructure	5	2-5	n/a	4
29CSA	1925	Computer Software - Business Apps	4-5	2-5	n/a	5
30OFF	1915	Office equipment	10	5-15	n/a	10
31SAF	1960	Safety Equipment	10	5-10	n/a	10
32BLD	1808	Buildings	60	50-75	n/a	60
33BLL	2005	Capital Lease - Building	Life of lease	n/a	n/a	Life of lease
34LND	1805	Land	n/a	n/a	n/a	n/a
38LHI	1810	Leasehold Improvements	10	n/a	n/a	10
39WHE	1935	Warehouse Equipment	10	5-10	n/a	10
40TLS	1940	Major Tools	10	5-10	n/a	7
41VHP	1930	Vehicles - Passenger	5-8	5-10	n/a	5
42VHT	1930	Vehicles - Light & Heavy	5-8	5-15	n/a	10
43VHO	1930	Vehicles - Other Mobile Equipment	5	5-20	n/a	10
44LMS	1970	Load Management	15	20	20	20

Oakville Hydro reclassified its capital assets to the new components effective January 1, 2010. However, as previously noted, due to the deferral of the implementation of IFRS, new useful lives were not applied to the new components until January 1st, 2013, as required by the Board.

As a result, Oakville Hydro has provided its continuity schedule for the 2013 Bridge Year to include the impact of componentization and the changes to useful lives. These changes are captured in the 2013 Bridge Year New CGAAP continuity statements, the impact of which is a decrease in depreciation expense and accumulated amortization of $3,541,709. Depreciation for the 2013 Bridge Year under CGAAP is $11,888,537 as shown in Table 2-54 and under New CGAAP is $8,346,829 as shown in Table 2-55.

The 2014 Test year also incorporates these changes and is reported in New CGAAP.

Table 2-54 - Continuity Statement – 2013 Bridge Year (Old CGAAP)

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	1,722,054			1,722,054	0			0	1,722,054
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	829,700			829,700	265,544	20,073		285,617	544,083
13	1810	Leasehold Improvements	3,505,475	72,500		3,577,975	1,190,359	354,173		1,544,532	2,033,444
47	1815	Transformer Station Equipment - Normally Prima	21,602,201	70,282		21,672,483	647,283	635,637		1,282,921	20,389,563
47	1820	Distribution Station Equipment - Normally Prima	7,310,742	608,156		7,918,899	2,558,874	281,283		2,840,157	5,078,741
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	22,547,385	2,664,937		25,212,322	5,959,170	906,014		6,865,185	18,347,137
47	1835	Overhead Conductors and Devices	31,791,864	1,643,509		33,435,373	12,148,124	1,321,573		13,469,697	19,965,676
47	1840	Underground Conduit	60,446,766	3,621,801		64,068,567	26,455,432	2,556,960		29,012,392	35,056,175
47	1845	Underground Conductors and Devices	46,080,876	4,597,350		50,678,225	17,990,209	1,991,093		19,981,302	30,696,923
47	1850	Line Transformers	44,916,673	2,167,544		47,084,217	20,215,405	1,838,004		22,053,410	25,030,808
47	1855	Services	9,684,898	849,542		10,534,440	1,480,039	404,387		1,884,426	8,650,014
47	1860	Meters	12,935,065	479,202		13,414,267	2,177,884	786,824		2,964,708	10,449,559
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	872,187			872,187	750,494	23,865		774,359	97,829
10	1920	Computer Equipment - Hardware	7,371,011	438,500		7,809,511	5,994,187	929,839		6,924,026	885,485
12	1925	Computer Software	5,286,592	1,086,974		6,373,566	4,395,627	405,316		4,800,943	1,572,622
10	1930	Transportation Equipment	4,488,353	638,008		5,126,361	2,439,959	569,003		3,008,961	2,117,400
8	1935	Stores Equipment	166,334			166,334	150,679	2,133		152,812	13,521
8	1940	Tools, Shop and Garage Equipment	1,279,206	115,439		1,394,645	866,772	98,593		965,365	429,280
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	8,098			8,098	3,248	810		4,058	4,040
47	1970	Load Management Controls - Customer Premise	171,648			171,648	171,648	0		171,648	0
47	1975	Load Management Controls - Utility Premises	49,876			49,876	49,876	0		49,876	0
47	1980	System Supervisory Equipment	4,486,620	244,000		4,730,620	2,381,175	266,741		2,647,916	2,082,703
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(41,494,285)	(4,289,005)		(45,783,290)	(9,836,144)	(1,745,551)		(11,581,696)	(34,201,594)
	2005	Property under Capital Lease	11,689,385			11,689,385	7,579,335	241,768		7,821,103	3,868,282
		Total before Work in Process	**257,748,723**	**15,008,738**	**0**	**272,757,460**	**106,035,180**	**11,888,537**	**0**	**117,923,717**	**154,833,743**
WIP	2055	Work in Process	1,792,056	(1,376,935)		415,121	0			0	415,121
		Total after Work in Process	**259,540,778**	**13,631,803**	**0**	**273,172,581**	**106,035,180**	**11,888,537**	**0**	**117,923,717**	**155,248,864**

Table 2-55 - Continuity Statement – 2013 Bridge Year (New CGAAP)

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
N/A	1805	Land	1,722,054			1,722,054	0			0	1,722,054
CEC	1806	Land Rights	0			0	0			0	0
47	1808	Buildings and Fixtures	829,700			829,700	265,544	20,299		285,843	543,857
13	1810	Leasehold Improvements	3,505,475	66,046		3,571,521	1,190,359	353,850		1,544,209	2,027,312
47	1815	Transformer Station Equipment - Normally Prima	21,602,201	61,115		21,663,316	647,283	505,223		1,152,507	20,510,810
47	1820	Distribution Station Equipment - Normally Prima	7,310,742	497,773		7,808,516	2,558,874	577,554		3,136,428	4,672,087
47	1825	Storage Battery Equipment	0			0	0			0	0
47	1830	Poles, Towers and Fixtures	22,547,385	1,765,679		24,313,064	5,959,170	428,003		6,387,173	17,925,891
47	1835	Overhead Conductors and Devices	31,791,864	1,012,210		32,804,074	12,148,124	553,538		12,701,662	20,102,412
47	1840	Underground Conduit	60,446,766	2,915,414		63,362,180	26,455,432	959,212		27,414,644	35,947,536
47	1845	Underground Conductors and Devices	46,080,876	3,596,714		49,677,590	17,990,209	1,283,772		19,273,981	30,403,609
47	1850	Line Transformers	44,916,673	1,718,934		46,635,608	20,215,405	955,669		21,171,075	25,464,533
47	1855	Services	9,684,898	635,533		10,320,431	1,480,039	212,547		1,692,587	8,627,844
47	1860	Meters	12,935,065	362,879		13,297,944	2,177,884	1,324,174		3,502,058	9,795,886
N/A	1865	Other Installations on Customer's Premises	0			0	0			0	0
N/A	1905	Land	0			0	0			0	0
CEC	1906	Land Rights	0			0	0			0	0
47	1908	Buildings and Fixtures	0			0	0			0	0
13	1910	Leasehold Improvements	0			0	0			0	0
8	1915	Office Furniture and Equipment	872,187			872,187	750,494	23,865		774,359	97,829
10	1920	Computer Equipment - Hardware	7,371,011	438,500		7,809,511	5,994,187	607,291		6,601,478	1,208,033
12	1925	Computer Software	5,286,592	1,062,977		6,349,568	4,395,627	379,393		4,775,020	1,574,548
10	1930	Transportation Equipment	4,488,353	583,203		5,071,556	2,439,959	346,046		2,786,005	2,285,551
8	1935	Stores Equipment	166,334			166,334	150,679	2,133		152,812	13,521
8	1940	Tools, Shop and Garage Equipment	1,279,206	107,902		1,387,108	866,772	187,319		1,054,091	333,017
8	1945	Measurement and Testing Equipment	0			0	0			0	0
8	1950	Power Operated Equipment	0			0	0			0	0
8	1955	Communication Equipment	0			0	0			0	0
8	1960	Miscellaneous Equipment	8,098			8,098	3,248	810		4,058	4,040
47	1970	Load Management Controls - Customer Premise	171,648			171,648	171,648	0		171,648	0
47	1975	Load Management Controls - Utility Premises	49,876			49,876	49,876	0		49,876	0
47	1980	System Supervisory Equipment	4,486,620	184,948		4,671,567	2,381,175	269,694		2,650,869	2,020,698
47	1985	Sentinel Lighting Rentals	0			0	0			0	0
47	1990	Other Tangible Property	0			0	0			0	0
47	1995	Contributions and Grants	(41,494,285)	(3,315,080)		(44,809,365)	(9,836,144)	(885,330)		(10,721,475)	(34,087,890)
	2005	Property under Capital Lease	11,689,385			11,689,385	7,579,335	241,768		7,821,103	3,868,282
		Total before Work in Process	**257,748,723**	**11,694,747**	**0**	**269,443,469**	**106,035,180**	**8,346,829**	**0**	**114,382,008**	**155,061,461**
WIP	2055	Work in Process	1,792,056	(1,476,748)		315,307	0			0	315,307
		Total after Work in Process	**259,540,778**	**10,217,999**	**0**	**269,758,777**	**106,035,180**	**8,346,829**	**0**	**114,382,008**	**155,376,768**

Capitalization of Burdens

Under IFRS, specifically International Accounting Standard ("IAS") 16, the cost of an item of PP&E includes only those costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. IAS 16 does not define the term "directly attributable". The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E. Where CGAAP allows for the capitalization of general and administrative overhead, IFRS does not.

Under Old CGAAP, in addition to purchase price, direct construction and direct development costs, Oakville Hydro included employee salaries and benefits and an allocation of overhead costs in the cost of an item of PP&E. These overhead costs were capitalized to PP&E by applying a predetermined rate (burden rate) to the direct costs. Burden rates are based on the cost expected to be incurred and vary by type of overhead cost.

Under Old CGAAP, Oakville Hydro applied the following burdens:

Benefit Burden – 58% of hourly line labour dollars. This burden recovers the company portion of the payroll costs, employee benefit programs provided by the company, training and any non-productive time.

Engineering/Operations Supervisory and Administrative Burden – 50% of hourly labour dollars. This burden recovers management time and General and Administrative costs of Engineering and Operations. Since management did not complete time cards for the hours directly attributable to a specific job, these costs are charged using a burden rate. (Note that the total labour burden under Old CGAAP was 108% - the sum of the benefit and engineering burdens)

Material Burden – 18% on the landed cost of all materials that flow through the warehouse. This burden recovers the costs of the warehouse, including staff wages and benefits, plus 75 % of the costs of the Purchasing department. This burden is applied to all materials that were handled by the warehouse.

Direct Material Burden – 5% on the landed cost of the materials that were shipped directly to the job site and were not handled by warehouse staff. The burden recovers the costs of processing the order and the receipt of those materials.

Subcontractor Burden – 15% on the invoice cost for services provided by a subcontractor. This burden recovers the contracting and supervision costs of Engineering and Operations staff for services provided by a subcontractor.

Vehicle Charges – Oakville Hydro maintains charge-out rates/hour by type of vehicle. Vehicles are charged to jobs using this hourly rate based on the # of hours the vehicle is used on the job. The charge-out rates recover all the operating costs of the fleet, including fuel, repairs and maintenance.

As part of the transition to IFRS, Oakville Hydro has reviewed its overhead costs to determine which continue to be appropriate directly attributable expenses to capitalize and which should be expensed as part of OM&A. Oakville Hydro determined the following burdens are directly attributable to PP&E and should therefore be capitalized:

Labour burden - this burden rate will consist of a direct benefit burden only and will be reduced from 108% to 30% to reflect the removal of the following:

- apprenticeship training and non-productive time which cannot be directly attributed to a specific job
- administration burden of 50% which recovered management time and General and Administrative costs of Engineering and Operations

The new CGAAP benefit burden of 30% recovers the benefits that employees are entitled to receive such as CPP, EI, medical and dental benefits, OMERS, EHT and WSIB. This burden is applied to hourly labour cost by specific job at 30% and is therefore directly attributable to an item of PP&E at the time the cost is incurred.

Vehicle Charges – with respect to repairs and maintenance, IFRS states that the costs of day-to-day servicing of an item of PP&E cannot be recognized in the carrying amount. These costs are expensed as incurred. Therefore the vehicle charge to capital will only include fuel and consumables.

Table 2-56 provides a summary of the change in burden rates from Old CGAAP to New CGAAP.

1 **Table 2-56 - Summary of Changes to Burdens**

Burden	Old CGAAP	New CGAAP
Labour	108% of hourly cost Direct benefits 22% (CPP, EI, dental, medical, OMERS, EHT, WSIB) Unproductive time 36% (training, weather, vacation, bereavement time, sick time, union business etc.) Administration burden 50% (Line Supervisor, P&C and engineering for oversight and project coordination)	30% of hourly cost Direct benefit 30% (CPP, EI, dental, medical, OMERS, EHT, WSIB)
Direct materials	5% charge to cover purchasing and payment processing	Nil
Subcontractors	15% charge to cover purchasing, payment processing, and engineering/operations supervision of capital projects	Nil
Warehouse	18% charge to cover purchasing and payment processing, storage costs and warehouse operations	Nil
Fleet	Hourly rate based on an allocation of maintenance costs, fuel and consumables and depreciation of equipment	Hourly rate to include only fuel and consumables

Due to the deferral of the implementation of IFRS until January 1, 2015, Oakville Hydro's new capitalization policy was not effective until January 1st, 2013, as required by the Board. As a result of the changes to the capitalization policy, Oakville Hydro has identified a total of $3,313,991 that is included in the 2013 capital budget under Old CGAAP that is not considered directly attributable to PP&E under New CGAAP. Table 2-57 provides the 2013 capital budget under Old CGAAP, totaling $15,008,738 compared to the New CGAAP budget of $11,694,747.

Table 2-57 - Old CGAAP 2013 Bridge Year vs. New CGAAP 2013 Bridge Year

Major Project	2013 Old CGAAP	2013 New CGAAP
27.6kV Additions	$1,879,441	$1,333,282
Distribution Meters / Wholesale Meter Upgrades	479,202	362,879
New Development / Services	1,412,561	1,102,130
Road Widening (Dependent on Road Work - No Hydro Control)	1,543,453	1,023,557
System Access	**5,314,658**	**3,821,848**
Alterations and Improvements for Load Transfer and System Security	572,150	471,194
Rebuild Overhead Distribution System	2,466,663	1,874,389
Rebuild Underground Distribution System	2,299,891	1,714,853
Substations	930,273	782,606
Supervisory Control and Communications	144,088	105,869
Transformer Replacements and Voltage Conversion	821,381	585,917
System Renewal	**7,234,446**	**5,534,829**
Administration - IT	45,000	45,000
Distribution Meters / Wholesale Meter Upgrades	77,000	77,000
Supervisory Control and Communications	108,214	79,443
System Service	**230,214**	**201,443**
Administration - Buildings	72,500	66,046
Administration - IT	1,403,474	1,379,477
Major Tools and Safety Equipment	115,439	107,902
Fleet	638,008	583,203
General Plant	**2,229,421**	**2,136,627**
Grand Total	**$15,008,738**	**$11,694,747**

Impact on Rate Base

In the 2013 Bridge Year, the net effect of the changes to Oakville Hydro's depreciation rates and capitalization policy is an increase to Rate Base of $558,179 as summarized in Table 2-58. Net Book Value has increased by $227,718 as a result of an increase of $3,541,709 due to the change in depreciation rates offset by a decrease of $3,313,991 due to the change in capitalization policy.

The working capital allowance at 15% has increased by $444,320 under new CGAAP as a result of increased operating expenses of $2,962,133 stemming from the transfer of 2013 burdens previously capitalized under old CGAAP. Burdens of $351,857 associated with 2012 WIP added in 2013 have not been transferred to expense in 2013, as these were incurred in 2012. A detailed reconciliation is provided in Table 2-59.

Table 2-58 - 2013 Bridge Year Old CGAAP vs. New CGAAP

Description	2013 Bridge Year Old CGAAP	2013 Bridge Year New CGAAP	Variance from 2013 Old CGAAP vs New CGAAP
Reporting Basis	CGAAP	CGAAP	
NET BOOK VALUE			
Gross Fixed Assets - Closing	$ 272,757,460	$ 269,443,469	-$ 3,313,991
Accumulated Depreciation - Closing	117,923,717	114,382,008	- 3,541,709
Net Book Value - Closing	154,833,743	155,061,461	227,718
Average Net Book Value	**153,273,643**	**153,387,502**	**113,859**
WORKING CAPITAL - 15% ALLOWANCE APPROACH			
Cost of Power	24,077,157	24,077,157	-
OM&A	2,274,221	2,718,541	444,320
15% Working Capital	**26,351,378**	**26,795,698**	**444,320**
Total Rate Base	**$ 179,625,021**	**$ 180,183,200**	**$ 558,179**

Table 2-59 - 2013 Bridge Year Impact of Accounting Changes to Rate Base, NBV, Expenses and Working Capital

Description	2013 Bridge Year Old CGAAP	2013 Bridge Year New CGAAP	Variance from 2013 Old CGAAP vs New CGAAP	Comments
Gross Fixed Assets - Excluding WIP Additions	$271,380,526	$268,418,392	($2,962,133)	Ineligible overheads incurred in 2013
2013 Additions from 2012 WIP	1,376,935	1,025,077	(351,857)	Ineligible overheads incurred in 2012; cannot be moved to 2013 expense but are included in 1576
Total Gross Fixed Assets - Rate Base	**272,757,460**	**269,443,469**	**(3,313,991)**	
Accumulated Depreciation	117,923,717	114,382,008	(3,541,709)	Change to depreciation rates
Net Book Value - Rate Base	**154,833,743**	**155,061,461**	**227,718**	
WIP	415,121	315,307	(99,814)	Ineligible overheads in 2013 WIP, incurred in 2012; not part of rate base but part of Total PP&E
Net Book Value - Total PP&E	**155,248,864**	**155,376,768**	**127,904**	Amount to be included in 1576
Rate of Return			7,637	Return on Rate Base associated with Account 1576 balance at Weighted Average Cost of Capital
Amount included in Deferral and Variance Rate Rider			**$135,541**	
Cost of Power and OM&A (A)	$175,675,852	$178,637,985	$2,962,133	Overheads expensed based on new capitalization polices
15% Working Capital (A * 15%)	$26,351,378	$26,795,698	$444,320	Impact to Working Capital at 15%

PP&E Deferral Account

Pursuant to the directives and guidance provided in the revised Accounting Procedures Handbook, Oakville Hydro has created a new deferral account to capture the difference in PP&E as a result of the accounting changes to depreciation expense and capitalization policies mandated by the Board in 2013.

Since Oakville Hydro is not planning to transition to IFRS until January 1st, 2015, it is using Account 1576 - Accounting Changes under CGAAP to record the required accounting changes in relation to depreciation expense and capitalization policies in 2013.

As detailed in Table 2-60, these accounting changes result in an increase in the 2013 Total PP&E of $127,904. This represents:

- ($3,313,991) decrease due to the change in capitalization policies on 2013 additions (in rate base)
- $3,541,709 increase due to the change in depreciation rates (in rate base)
- ($99,814) decrease due to the change in capitalization policies on 2013 WIP (not in rate base)

Oakville Hydro has based the calculation of Account 1576 Accounting Changes under CGAAP on PP&E balances including work-in-progress (WIP). This treatment is described below and is consistent with the treatment proposed by PowerStream Inc. in their Cost of Service Application EB-2012-0161 and addressed in Undertaking JT1.4: “Further Clarification re PowerStream’s calculation of Account 1575 IFRS Transitional PP&E Amount (Issue 8.2)”.

The reason for including WIP is that it is a part of PP&E and its addition to rate base is an issue of timing. If Oakville Hydro was continuing on old CGAAP, the amount of WIP at December 31, 2012 of $415,121 would be added to rate base in 2014. Under New CGAAP, $315,307 of WIP is added to rate base in 2014. The amount not capitalized under New CGAAP becomes an out of period cost with respect to current rates unless it is captured in account 1576. To include only the portion of the amount pertaining to PP&E additions that become in-service, results in the portion pertaining to WIP becoming an "out of period" cost. Therefore it must be included in PP&E and captured in account 1576.

Since the calculation of Account 1576 is based on the 2013 Bridge Year forecast, Oakville Hydro would like to re-calculate Account 1576 using 2013 Actuals when they become available in the first quarter of 2014. If the result is materially different from that calculated using the 2013 Bridge Year forecast, Oakville Hydro requests the option to use the 2013 actual figures for the PP&E Deferral account.

Table 2-60 - Impact of Accounting Changes – Total PP&E

Description	2013 Bridge Year - Old CGAAP	2013 Bridge Year - New CGAAP	Variance Old CGAAP vs. New CGAAP
Reporting Basis	CGAAP	CGAAP	CGAAP
PP&E			
Gross Fixed Assets - Rate Base	$272,757,460	$269,443,469	($3,313,991)
Accumulated Depreciation	117,923,717	114,382,008	(3,541,709)
Total PP&E before WIP, as per 2-BA1	**$154,833,743**	**$155,061,461**	**$227,718**
Work In Progress	415,121	315,307	(99,814)
Total PP&E including WIP	**$155,248,864**	**$155,376,768**	**$127,904**

These accounting changes for the 2013 Bridge Year result in a higher New CGAAP Total PP&E in comparison to that calculated under old CGAAP. Accordingly USofA Account 1576 - Accounting Changes under CGAAP represents amounts owing to customers. A schedule of Accounting Changes under CGAAP (Board Appendix 2-EE) is provided below.

Appendix 2-EE
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2010 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2016	2017
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				$153,505,598					
Net Additions - Note 4				13,631,803					
Net Depreciation (amounts should be negative) - Note 4				-11,888,537					
Closing net PP&E (1)				155,248,864					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1				153,505,598					
Net Additions - Note 4				10,217,999					
Net Depreciation (amounts should be negative) - Note 4				-8,346,829					
Closing net PP&E (2)				155,376,768					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP				-127,904					

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-127,904	**WACC**	5.97%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-7,637	**# of years of rate rider disposition period**	1
Amount included in Deferral and Variance Account Rate Rider Calculation	($135,541)		

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, the PP&E values as of January 1, 2013 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:

the variance account opening balance as of 2014 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

1 4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

In accordance with the Board's letter issued June 25, 2013 Oakville Hydro has calculated a rate of return component to be applied to the balance in Account 1576 in Table 2-61 below.

Table 2-61 - Calculation of Account 1576 Rate Rider

Description		Calculation	Total
2013 Closing Balance PP&E Old CGAAP		A	$155,248,864
2014 Closing Balance PP&E New CGAAP		B	155,376,768
Closing Balance in Account 1576		C = A - B	(127,904)
WACC		D	5.97%
Return on Rate Base Associated with Account 1576 balance at WACC	per year	E = C * D	(7,637)
Disposition Period		F	1
Return on Rate Base Associated with Account 1576 balance at WACC	total	G = E * F	(7,637)
Amount included in Account 1576 Rate Rider Calculation		**H = C + G**	**($135,541)**

The disposition of Account 1576 and the associated rate of return component are discussed in further detail in Exhibit 9, Tab 6.

Appendix A

Distribution System Plan




OAKVILLE HYDRO
ELECTRICITY
DISTRIBUTION

Distribution System Plan

September 13, 2013

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Distribution System Plan

On March 28, 2013 the Board issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, entitled *Consolidated Distribution System Plan Filing Requirements* ("DS Plan Filing Requirements"). The filing requirements provide a standard approach to a distributor's filing of asset management and capital expenditure plan information in support of a rate application. Oakville Hydro's Distribution System Plan ("DS Plan") has been prepared in accordance with the DS Plan Filing Requirements. Oakville Hydro has organized the required information using the section headings in the DS Plan Filing Requirements.

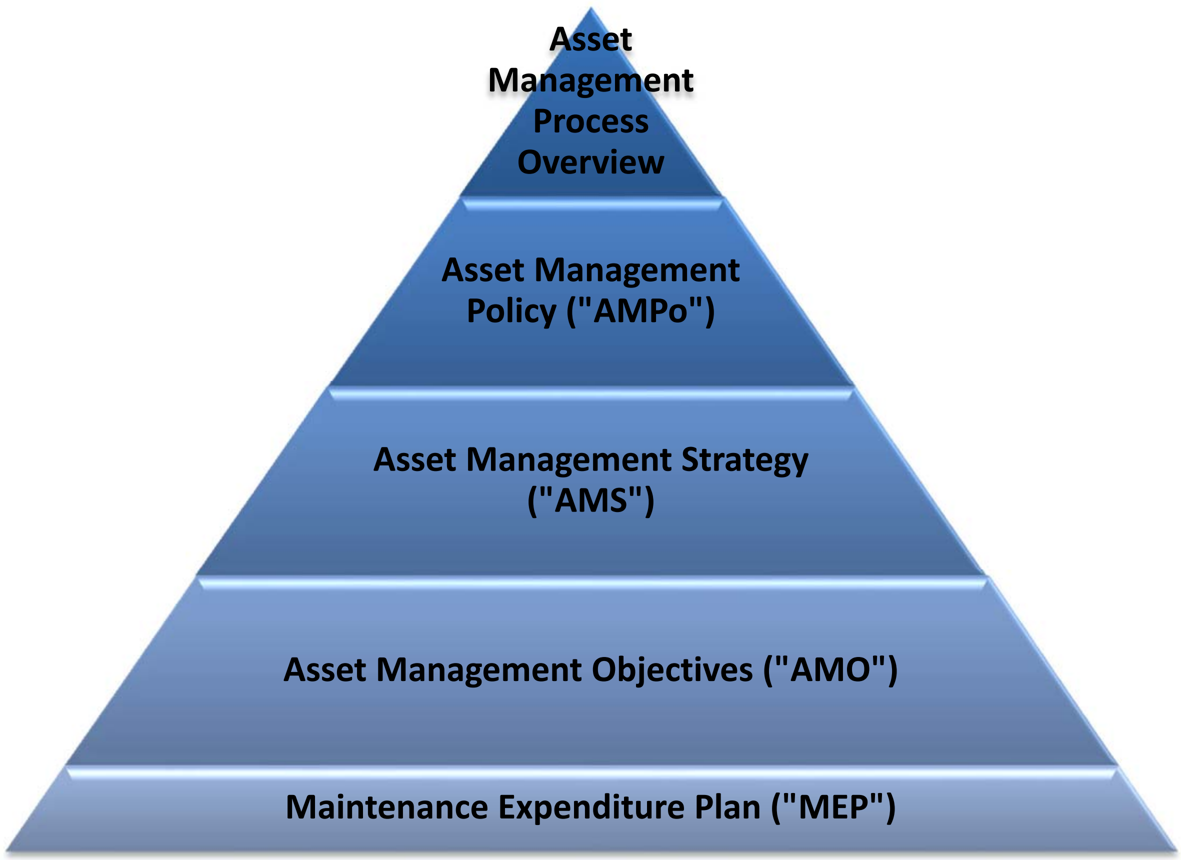
Oakville Hydro's DS Plan is an integrated document that supports the cost-effective planning and operation of the electricity distribution network – a network that is efficient, reliable, sustainable, and provides value for customers. The DS Plan documents the practices, policies and processes that are in-place to ensure that investment decisions support Oakville Hydro's desired outcomes in a cost effective manner and provides value to the customer. Oakville Hydro is committed to adhering to its DS Plan in order to provide the valued outcomes to the customer. Electricity distributors are capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network.

Distribution System Plan Overview

Asset Management Process

Oakville Hydro has enhanced its Asset Management process since its last cost of service application. In 2010 Oakville Hydro created and filled a new position – Supervisor, Asset Management. This position is dedicated to managing distribution assets and the associated asset management process and is responsible for assessing the need for capital asset replacements as well as formalizing asset maintenance activities to optimize the life of the assets. In 2012 Oakville Hydro began implementation of an Asset Management Process ("AMP"). Oakville

Hydro's Board of Directors has reviewed the Asset Management Strategy. The AMP consists of the documents listed below which are provided as appendices to the DS Plan in Appendix 1 of the DS Plan.



In 2012, Oakville Hydro began implementation of an Asset Management system to provide the tools necessary to execute its Asset Management process. One component of the Asset Management system, the Computerized Maintenance Management System ("CMMS"), contains a record of all patrols and maintenance activities performed on all assets. The CMMS enables Oakville Hydro to optimize the tracking of equipment, scheduling of patrols, the performance of maintenance and the timing of capital replacements. The CMMS is currently being populated with the specific asset information for all of Oakville Hydro's major distribution assets. In 2014, existing condition assessments will be migrated into the CMMS from the current Microsoft Access Database and by 2015 field staff will enter condition assessment information directly into this CMMS.

As detailed in the section on the 20-Year Capital Asset View of Appendix 1.3, Asset Management Objectives document to the DS Plan, Oakville Hydro has prepared a capital expenditure forecast for 20 years. The 20-year plan is intended to provide directional information on forecasted capital expenditures as conditions will change with a planning period of this length. However, in accordance with the DS Plan Filing Requirements, Oakville Hydro's DS Plan covers the most recent five year historical period and the forecast for the next five years. A five year planning horizon provides a more reasonable assessment of the level of capital investment required.

Prospective Business Conditions

Oakville Hydro's residential customer base, which represents approximately 90% of its total customer base, continues to grow at a modest pace. The *Best Planning Estimates of Population, Occupied Dwelling Units and Employment, 2011-2031* published by the Region of Halton in June 2011 forecast that the population in Oakville Hydro's service will increase by approximately 35% from 2011 to 2031 with the majority of the growth expected to occur in greenfields. However, actual growth has been slower than forecasted in and Oakville Hydro anticipates growth of approximately one to two per cent per year over the five-year planning horizon with the majority of the growth occurring in greenfield areas not currently connected to Oakville Hydro's distribution system.

Oakville Hydro has been proactive in planning for this growth. In 2011 Oakville Hydro designed and constructed the Glenorchy Municipal Transformer Station to address the capacity constraints and provide for future growth. In August 2013, Milton Hydro connected to Oakville Hydro's distribution system at the Glenorchy Municipal Transformer Station and became an embedded distributor. The addition of Milton Hydro, as an embedded distributor, will benefit Oakville Hydro's customer base by allowing Oakville Hydro to recover a portion of the costs associated with the Glenorchy Municipal Transformer Station.

While the residential customer base is growing, Oakville Hydro's commercial and industrial customer base continues to remain relatively stable. Growth in the industrial and manufacturing industries has not fully recovered from the economic recession. This is evidenced by the announcement published in June 2013 by the Ford Motor Company, a wholesale market participant (that is connected to the grid and is not one of Oakville Hydro's customers) that its contract with a manufacturer of auto parts with two plants in Oakville Hydro's service area will end. The manufacturer has announced that it will close in 2014, after only seven years of operation in the Town of Oakville. In addition, Kraft Canada has announced the closure of its Oakville plant in the third quarter of 2013. The Town of Oakville's Economic Development department dedicates resources to attracting industrial and commercial customers to the Town of Oakville (which it is hoped) will offset some of the impact of these losses. However, this is a difficult and long term process.

In December 2015 a new Regional hospital, currently under construction, is expected to open in the northern region of the Town of Oakville. Following the transfer of all patients and services to from the current hospital to the new site in December 2015, the current hospital will close. The Town of Oakville has undertaken a public consultation regarding the future use of the property as part of its ongoing planning. Oakville Hydro is currently providing service to the hospital during its construction and has included the costs associated with the construction of distribution assets to service their energy needs in its DS Plan.

Contingencies

There are a number of aspects of Oakville Hydro's DS Plan that are contingent upon the outcome of ongoing activities or future events. In preparing its DS Plan, Oakville Hydro has initiated consultation with neighbouring distributors and Hydro One, the lead transmitter serving Oakville Hydro. As discussed in the following section, Oakville Hydro requested a letter confirming the status of regional planning for the two Regional Planning areas of which Oakville Hydro is a member of (GTA West and Burlington to Nanticoke) and requesting a Regional Planning session with the appropriate resources. However, as noted by the Board in the proposed amendments to the Transmission System Code (the "TSC") and the Distribution System Code (the "DSC") issued on May 17, 2013, it will take approximately four years to complete the transitional planning process. In the event that Oakville Hydro is required to make material investments as a result of the Regional Planning process, it will use the appropriate rate adjustment mechanism to seeking approval for the recovery of those costs.

As discussed in Appendix 1, of Oakville Hydro's 2014 Cost of Service Application, Oakville Hydro has had preliminary discussions with Enersource Inc. ("Enersource") regarding the elimination of load transfers, for approximately ten customers. The proposed solution to eliminate the load transfer is to have Oakville Hydro acquire the related assets from Enersource. Preliminary discussions have indicated that the investment will not be material and therefore Oakville Hydro has not included the costs associated with the acquisition in its 2014 DS Plan.

Coordinated Planning with Third Parties

On May 17, 2013 the Board provided notice of proposed amendments to the TSC and the DSC the purpose of which was to implement the Board's policies set out in its October 18, 2012 *Report of the Board – A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (the "RRFE Board Report"). The proposed amendments related to, among other things, the establishment of a process in order to move to a more structured approach to regional infrastructure planning.

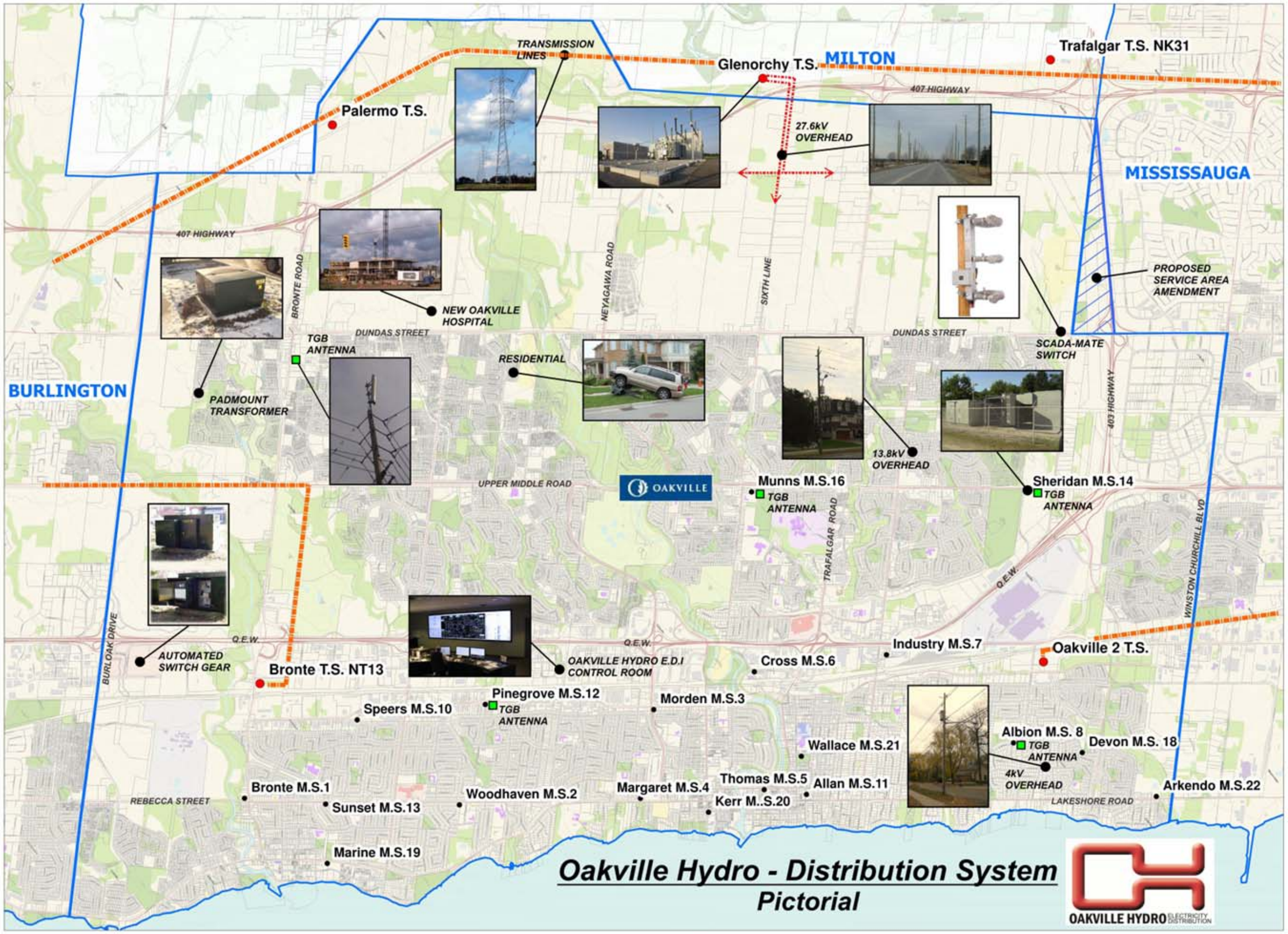
As noted in the RRFE Board Report, regional planning is not a new concept in Ontario. Oakville Hydro has been working with Hydro One Networks Inc. ("Hydro One"), the Ontario Power Authority ("OPA"), the Independent Electricity Systems Operator ("IESO"), and its neighbouring electricity distributors for a number of years. Oakville Hydro was invited to attend a regional planning session with Hydro One, the OPA and the IESO on May 17, 2012 to discuss a number of regional issues including the load forecast for Oakville Hydro's service territory, the West GTA Planning Region, load restoration and the regional planning process.

At that time, there were two capacity constraints identified that could be relieved temporarily through load transfers. The Richview to Manby/Cooksville 230 kV system was approaching capacity limits and the IESO and Hydro One suggested that the transfer of load from the Oakville Transformer Station to other Transformer Stations supplying Oakville Hydro could relieve the capacity constraints until such time as the IESO and Hydro One could implement a solution. The second opportunity related to the Cooksville/Oakville 230 kV line section of line which was an area requiring assessment. Oakville Hydro indicated that it had load transfer capability of about 10-15 MW through remotely-operated sectionalizing of load from Oakville Transformer Station to Trafalgar Transformer Station and Bronte Transformer Station that could be used to relieve capacity constraints.

In discussions regarding the RRFE Board Report, the OPA identified that the West GTA Planning area was likely a candidate for regional planning for a number of reasons including increasing west to east flows caused by changing supply mix, e.g. renewable resource penetration in southwestern Ontario, increased local load growth in Mississauga, Oakville, Milton, Halton Hills, and Brampton and the retirement and refurbishment of nuclear resources at Pickering and Darlington. A number of potential changes were discussed including increased transformation capacity, relief of Trafalgar to Richview 230 kV circuit loading through reconfiguration of the 230 kV system, and load restoration for the Cooksville to Oakville line section.

In addition to the Regional Planning Process, Oakville Hydro frequently works with Hydro One to manage capacity constraints on an informal and as-needed basis. Oakville Hydro is unique in that it is fed by three separate transmission supplies and Oakville Hydro is often called upon by Hydro One to perform short-term load transfers around its distribution system to alleviate capacity constraints within the region. Oakville Hydro has designed its system to accommodate these requests. A map illustrating Oakville Hydro's Service Area and the location of its Municipal Stations is provided below.

Oakville Hydro's Service Area



Oakville Hydro has also worked closely with neighbouring distributors, where possible, to facilitate regional planning. In 2003, Oakville Hydro entered into a connection agreement with Burlington Hydro to provide and maintain two electricity distribution lines from Hydro One's transformer station located at Bronte Road and Wyecroft Road in Oakville to the Burlington Hydro switches located at Burloak Drive to connect the Burlington distribution system to the Oakville distribution system which would allow Burlington to receive electricity from the feeder lines.

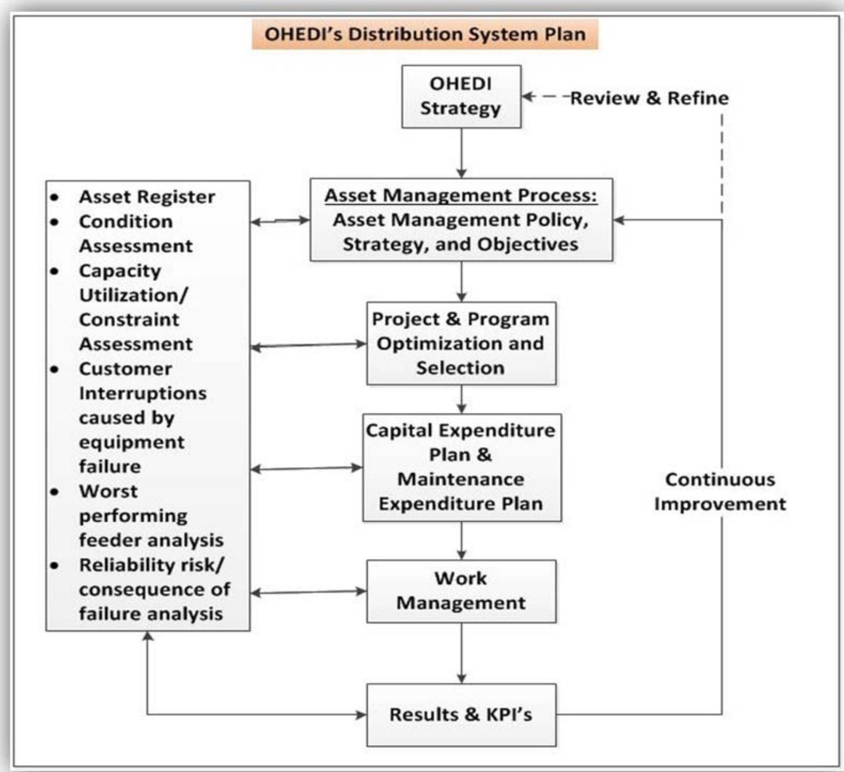
More recently, Oakville Hydro has entered into a 10-year connection agreement with Milton Hydro Electricity Distribution Inc. to provide two feeder positions at Glenorchy Municipal Transformer Station located at 4322 Sixth Line in the Town of Milton, Ontario, to serve a portion of Milton Hydro's service area as this area continues to grow at a fast pace.

As discussed previously, Oakville Hydro sent a letter to the lead transmitter in Oakville Hydro's planning regions, Hydro One, requesting that Hydro One provide Oakville Hydro with a letter confirming the status of regional planning for the two Regional Planning areas of which Oakville Hydro is a member, GTA West and Burlington to Nanticoke, and requesting a Regional Planning session with the appropriate resources. A copy of that letter is provided as Appendix 2 to the DS Plan.

Hydro One provided an update on the status of Regional Planning on September 5, 2013. A copy of that document is provided as Appendix 3 to the DS Plan. In its letter, Hydro One confirmed that the Regional Planning Process has not been initiated and a Regional Infrastructure Plan has not been developed within the GTA West region or the Burlington to Nanticoke Region. Hydro One expects that regional planning will be initiated in the fourth quarter of 2013. Hydro One and Oakville Hydro have begun discussions regarding Hydro One's preliminary information requirements to initiate the regional planning consultation for the two planning regions. However, based on the information received from Hydro One, Oakville Hydro is unable to assess whether the regional planning consultation will affect the DS Plan.

Performance Measurement for Continuous Improvement

As illustrated in Appendix 1.2, Asset Management Strategy and reproduced below, Oakville Hydro has implemented a process for the continuous review and refinement of its Asset Management Process through Key Performance Indicators ("KPI's) such as the evaluation of asset condition, capacity utilization, performance measures, worst performing circuits and risk consequence failure analysis. In addition to customer-oriented reliability measures, Oakville Hydro continuously monitors the cost efficiency and effectiveness of its performance against the DS Plan to ensure that capital spending is in accordance with this DS Plan and that innovative measures are taken where necessary to control costs.

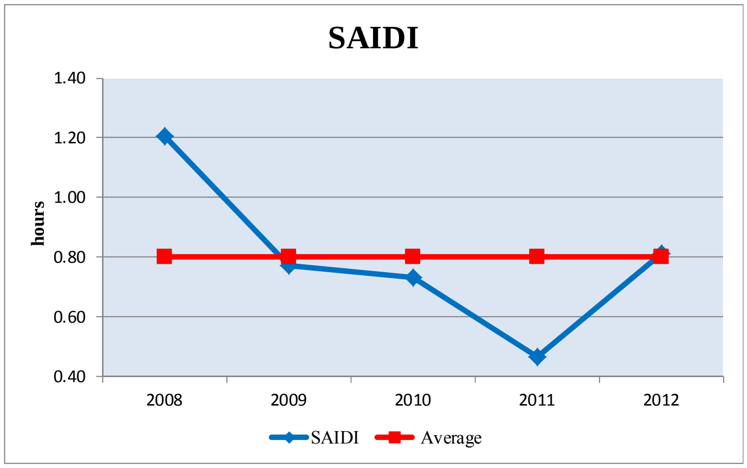


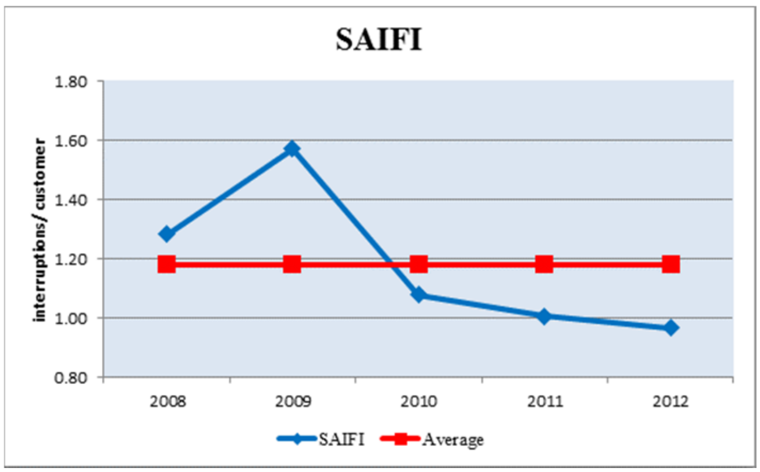
Performance Trends - Service Quality and Reliability

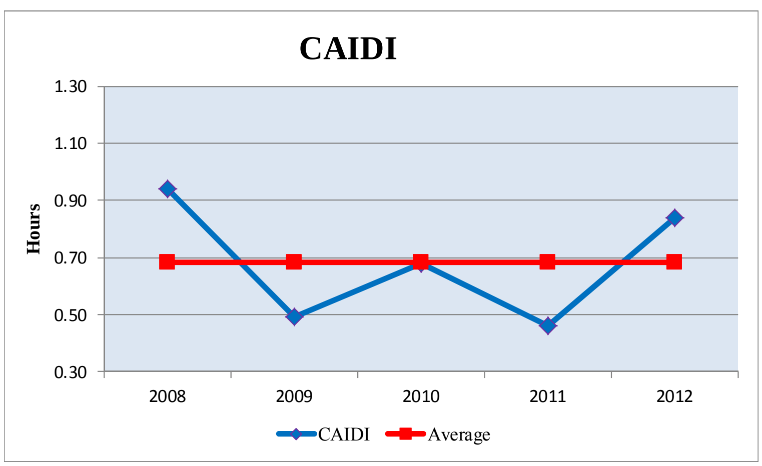
Oakville Hydro tracks service reliability statistics such as, System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI"), including and excluding loss of supply-related incidents, and reports these to the Ontario Energy Board on an annual basis. These measures form part of Oakville Hydro's corporate performance measures which are reported to Oakville Hydro's Board of Directors. Oakville Hydro's performance is within Oakville Hydro's range of performance which Oakville Hydro has defined as the average over the previous five years. Table 1 – Service Reliability Statistics, summarizes the service reliability indicators (SAIDI, SAIFI, CAIDI) for the five historical years. The graphs on the following page illustrate Oakville Hydro's performance as compared to the five year average. Oakville Hydro has provided reliable service to its customers over the five year historical period and is dedicated to continue providing this level of service to its customers over the planning horizon.

Table 1 - Service Reliability Statistics

Year	SAIDI	SAIFI	CAIDI
	hours	interruptions/ customer	hours
Including Loss of Supply			
2008	1.54	1.60	0.96
2009	0.77	1.57	0.49
2010	0.74	1.15	0.65
2011	0.47	1.04	0.45
2012	0.81	0.97	0.84
5 Years Rolling Average	**0.87**	**1.27**	**0.68**
Excluding Loss of Supply			
2008	1.21	1.28	0.94
2009	0.77	1.57	0.49
2010	0.73	1.08	0.68
2011	0.46	1.01	0.46
2012	0.81	0.97	0.84
5 Year Rolling Average	**0.80**	**1.18**	**0.68**


SAIDI
hours
1.40
1.20
1.00
0.80
0.60
0.40
2008
2009
2010
2011
2012
SAIDI
Average


SAIFI
interruptions/ customer
1.80
1.60
1.40
1.20
1.00
0.80
2008
2009
2010
2011
2012
SAIFI
Average


CAIDI
Hours
1.30
1.10
0.90
0.70
0.50
0.30
2008
2009
2010
2011
2012
CAIDI
Average

Asset Management Process

Asset Management Process Overview

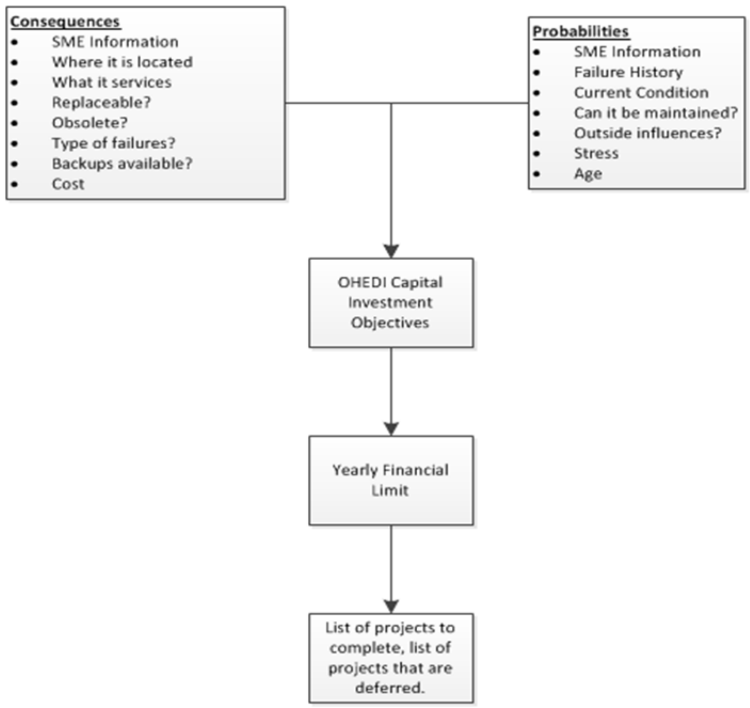
Oakville Hydro's has adopted a renewed approach to distribution system planning to formalize the management of distribution assets. Oakville Hydro's Asset Management process incorporates relevant strategies associated with integrated capital investment, asset maintenance and asset retirement. The objectives are derived from, and are consistent with, the goals of Oakville Hydro's corporate goals and strategic imperatives.

As detailed in the Major Distribution Asset Replacement section of Appendix 1.2 Asset Management Strategy, Oakville Hydro uses a number of components to prepare its capital expenditure plan. These components are listed below.

- Asset Management Components (inputs/outputs):
- Asset Register
- Condition Assessments & Recommendations
- Asset Capacity Utilization/Constraint Assessment
- Reliability-Based 'Worst Performing Feeder" Information and Analysis SAIDI, CAIDI, and SAIFI metrics.
- Interviews with Subject Matter Experts ("SME's")
- Optimization of Project Portfolios
- Typical Useful Lives

The following diagram illustrates the information primary process steps, and information flows used by the Oakville Hydro to identify, select and prioritize investments.

Selection and Prioritization Process



Overview of Assets Managed

As detailed in Oakville Hydro's Asset Management Process Overview document as found in Appendix 1, Oakville Hydro distributes electricity to more than 65,000 customers within its service area through a network of remotely switched power lines of approximately 1,400 circuit km, 55% of the system underground and 45% overhead. Oakville Hydro's distribution system is supplied from four Hydro One owned transformer stations and one Oakville Hydro owned Municipal Transformer Station. The service area is approximately 143 square kilometers and is primarily urban. Oakville is considered in the "Dfb" or "Warm Summer Continental" climate of the Köppen climate classification. Extreme minimum temperature recorded at -30°C and extreme maximum temperature recorded at 38°C with average temperatures ranging between -4.9°C and 20.7°C. Seasonal precipitation ranges between 44.2mm to 78.5mm.

Asset Information and Vintage of Information

Information regarding Oakville Hydro's assets by asset type, including the quantity and years in service is found in Oakville Hydro's Appendix 1.2, Asset Management Strategy of the DS Plan in the section entitled Major Distribution Assets and reproduced below. This data was compiled in September, 2012 and is summarized below.

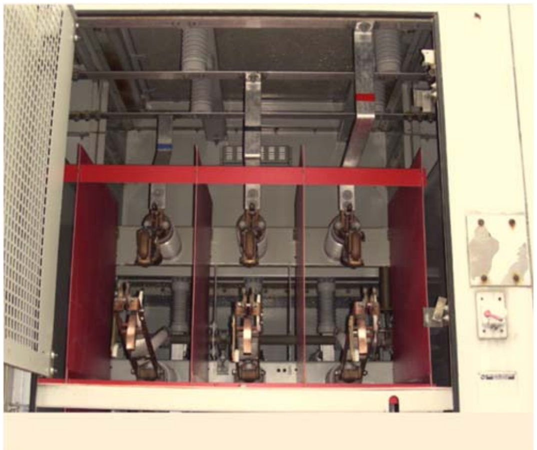
Low Voltage Station Switches (4.16 & 13.8kV)

Quantity:	20
Average Age:	2.4 Year(s)
Range:	2-3 Year(s)
Strategy:	Proactive

Low Voltage Switch Breakers (4.16 & 13.8kV)

Quantity:	87
Average Age:	26.2 Year(s)
Range:	1-43 Year(s)
Strategy:	Proactive

High Voltage Station Switches (2.7kV Open Air)

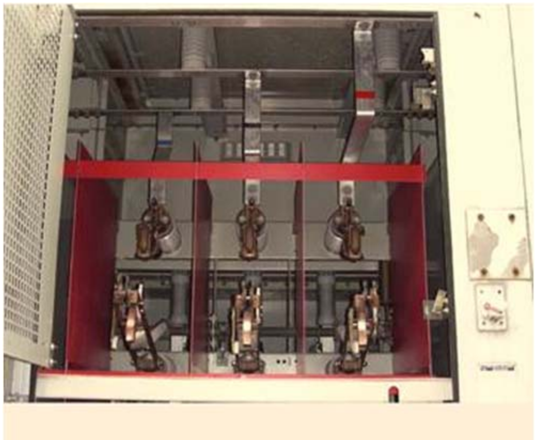


Quantity:	38
Average Age:	35.5 Year(s)
Range:	1-55 Year(s)
Strategy:	Proactive

High Voltage Station Switches (27.6kV GIS)

Quantity:	46
Average Age:	1 Year(s)
Range:	1 Year(s)
Strategy:	Proactive

High Voltage Station Breakers (27.6kV)



Quantity: 21

Average Age: 1 Year(s)

Range: 1 Year(s)

Strategy: Proactive

High Voltage Station Switches (230kV)

Quantity: 2

Average Age: 1 Year(s)

Range: 1 Year(s)

Strategy: Proactive

Overhead Distribution Transformer

Quantity:	1812
Average Age:	25.9 Year(s)
Range:	1-72 Year(s)
Strategy:	Run-to Failure

Padmount Distribution Transformer

Quantity:	4857
Average Age:	16.8 Year(s)
Range:	1-49 Year(s)
Strategy:	Run-to Failure

Submersible Distribution Transformer

Quantity:	1235
Average Age:	18.1 Year(s)
Range:	1-46 Year(s)
Strategy:	Run-to Failure

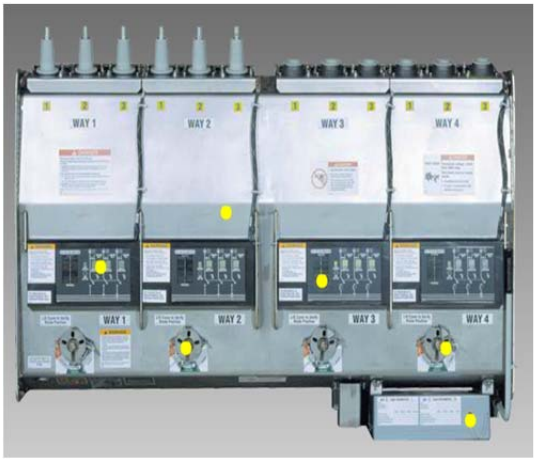
Vault-style Distribution Transformer

Quantity:	223
Average Age:	38.5 Year(s)
Range:	13-63 Year(s)
Strategy:	Proactive

Padmount Switchgear

Quantity:	170
Average Age:	23 Year(s)
Range:	1-42 Year(s)
Strategy:	Proactive

Vault-style Switchgear



Quantity:	11
Average Age:	12 Year(s)
Range:	6-42 Year(s)
Strategy:	Proactive

Overhead Gang-Operated Switch

Quantity:	123
Average Age:	28 Year(s)
Range:	1-31 Year(s)
Strategy:	Proactive

Overhead Primary Wire Circuit Kilometers

Quantity:	561
Average Age:	28 Year(s)
Range:	1-71 Year(s)
Strategy:	Run-to Failure

Underground Primary Wire Circuit Kilometers

Quantity:	894
Average Age:	22 Year(s)
Range:	1-43 Year(s)
Strategy:	Proactive

Poles – Mostly Wood

Quantity:	8004
Average Age:	25 Year(s)
Range:	1-71 Year(s)
Strategy:	Proactive

Secondary Cable Kilometers

Quantity:	1067
Average Age:	22 Year(s)
Range:	1-71 Year(s)
Strategy:	Run-to Failure

Meters

Quantity:	64,652
Average Age:	1.6 Year(s)
Range:	1-30 Year(s)
Strategy:	Proactive

Primary Meters

Quantity:	44
Average Age:	20 Year(s)
Range:	1-42 Year(s)
Strategy:	Run-to Failure

Remote Terminal Units (RTUs)

Quantity:	116
Average Age:	10 Year(s)
Range:	1-20 Year(s)
Strategy:	Proactive

Asset Capacity Utilization

As discussed in Oakville Hydro's Asset Management Objectives, Oakville Hydro reviews capacity utilization at the transformer station connection points (at 27.6 kV) and at the 27.6 kV feeder level, on an individual feeder basis annually. The review is normally done at the time of the annual system peak, to most accurately determine the system capacity utilization. The System Control and Data Acquisition ("SCADA") System is used to monitor feeder loads and assists in the capacity utilization review. For new developments in North Oakville, at present, the assessment is very straightforward due to the recent addition of the Oakville Hydro's Glenorchy Municipal Transformer Station and associated new 27.6kV feeders. At present there is available capacity for new loads in this area. For new load additions in established areas, capacity utilization and constraint assessment is done on a project by project basis to determine if upgrades or load transfers to other feeders are necessary.

Asset Lifestyle Optimization Policies and Practices

In managing its assets, Oakville Hydro applies sound technical, social, financial and economic principles that consider present and future needs. Oakville Hydro's asset management policies and practices are provided in Appendix 1.1, Asset Management Policy and reproduced below.

To guide Oakville Hydro the following policy statements have been developed:

a) Oakville Hydro will continuously refine its asset management program to meet system capacity, reliability, security and operating requirements while ensuring long term affordability and responsible stewardship of the distribution system.
b) Oakville Hydro will continue to meet and maintain regulatory and service requirements, employing good utility practices, while balancing between customer expectations and lifecycle costs.

c) Oakville Hydro will maintain compliance to health and safety policies, environmental regulations, and electricity rates and filing requirements.

d) Oakville Hydro will optimize capital and maintenance costs throughout the lifecycle of the asset, and corporate value will be enhanced through timely asset renewal.
e) Oakville Hydro will drive asset investment decisions through condition-based system analysis with a goal to extend asset useful life, as appropriate.
f) Oakville Hydro will incorporate the requirements for system growth and asset replacement or renewal decisions as noted in Oakville Hydro's Smart Grid Strategy and Ontario's Green Energy Act.
g) Oakville Hydro will incorporate the elements of the Asset Management Strategy in long term distribution system planning.
h) Oakville Hydro will continually assess evolving technologies for consideration and potential application.

Asset Maintenance Strategy

As detailed in Appendix 1.2, Asset Management Strategy, Oakville Hydro utilizes a combination of patrols and maintenance activities to complete inspection requirements, and records information regarding the condition of distribution assets. A minimum of one-third of each major asset is either patrolled or has maintenance performed each year in order to ensure all assets are inspected a minimum of once every three years. During the patrol, minor maintenance or critical items, that may be immediately addressed, are resolved and reported. Major maintenance that requires more complex coordination is subsequently scheduled for completion within the year, or planned for future years.

Oakville Hydro analyzes the information gathered during the inspection and maintenance routines, as part of condition-based asset assessments. Decisions to replace assets versus proceeding with ongoing maintenance to extend the life of the asset are determined based on a business case assessment.

Asset Life Cycle Risk Management Policies and Practices

Investment Objectives

As detailed in Appendix 1.2, Asset Management Strategy, the optimization of future programs and project portfolios allows Oakville Hydro to ensure that future expenditures will be applied effectively to the appropriate areas of the system to mitigate risk to Oakville Hydro Capital Investment Objectives described below. The risk is assessed by considering probability and consequence to these Objectives if a project or a program is not completed.

Financial

- When assessing the impact on the financial value, Oakville Hydro must consider the mitigation of maintenance expenditures, mitigation of lost revenue due to decreasing reliability, and mitigation of future capital expenditures, through the completion of the proposed projects and programs package, replacement of ageing assets, and maintenance practices. Oakville Hydro's goal is to reduce costs associated with maintaining aging equipment and to mitigate, to the extent possible, future lost revenue due to lower reliability.

Service Quality

- When assessing risk to the SAIFI and SAIDI measures, Oakville Hydro considers the impact on SAIFI and SAIDI through completion of the proposed projects and programs-package, replacement of ageing assets, and maintenance practices. The Service Quality risk is measured by the number of customers that will be without power due to failure of the assets included within the proposed projects and programs package, and its measures are the types of customers affected, number of feeders affected and improvements in SAIFI and SAIDI. Oakville Hydro's goal is to establish a downward trend in SAIFI and SAIDI.

Socio-Political

- When assessing the impact to the community image value, Oakville Hydro considers customer satisfaction as measured by the number of written or verbal complaints received. The risk is also measured by the complaint escalation level, ranging from Individual concerns made to the company to General public outcry – national media coverage. Oakville Hydro's goal is to reduce customer concerns and media focus, and minimizing complaints escalation.

Legal

- When assessing legal risk Oakville Hydro assess the cost and number of potential litigations brought against Oakville Hydro to minimize legal fees associated with capital projects, e.g. acquiring easement rights. Oakville Hydro's goal is to reduce litigation costs, and minimize, to the extent possible, legal costs.

Regulatory

- The regulatory risk is measured by severity of possible non-compliance that could occur due to assets within the proposed projects and programs package. Oakville Hydro's goal is to reduce regulatory compliance issues, and mitigate potential future regulatory non-compliance situations.

Safety

- This value deals with ensuring that both Oakville Hydro's employees work in a safe environment and that potential known public safety hazards are eliminated or minimized to the extent possible. Oakville Hydro's goal is the reduction in existing employee and public safety issues, and mitigation of exposure to potential safety hazards.

Environmental

- Environmental risk is measured by the potential severity of environmental issues due to the assets within the proposed projects and programs package, ranging from minor disturbance, documentation not necessary to disturbance requiring Ministry of Environment assistance and public evacuation. Oakville Hydro's goal is to reduce existing environmental incidents and mitigate.

In order to provide value added risk disciplined decision making Oakville Hydro has assigned weightings to the above noted Capital Investment Objectives. The weightings ensure that capital investments are prioritized appropriately to mitigate the highest risks. The following figure shows the weighting of each of the objectives.

Capital Expenditure Plan

Summary

In managing its distribution system assets, Oakville Hydro's main objective is to optimize the performance of its assets at a reasonable cost, with due regard for customer service expectations, system reliability and public and employee safety. This application provides detailed information on Oakville Hydro's Capital Expenditure Plan for the 2014 Test Year and high level information on capital expenditures for the forecast period 2015 to 2018. These capital expenditures are summarized in Table 2, Capital Expenditure Plan. In accordance with the DS Plan Filing Requirements, Oakville Hydro has categorized its forecasted capital expenditures using the Board's investment categories.

Table 2, Capital Expenditure Plan

CATEGORY	2014	2015	2016	2017	2018
System Access	$ 2,322	$ 2,130	$ 2,448	$ 2,497	$ 2,639
System Renewal	5,980	5,436	5,505	5,599	5,599
System Service	5,589	559	581	605	629
General Plant	2,717	2,126	2,866	2,052	2,063
TOTAL EXPENDITURE	$ 16,607	$ 10,251	$ 11,401	$ 10,752	$ 10,931

As discussed previously and as detailed in Appendix 1.3 - Asset Management Objectives, Oakville Hydro optimizes future capital expenditures through an objective weighting analysis to ensure that expenditures are applied effectively to the appropriate areas of the distribution system to mitigate risk. In addition, Oakville Hydro is conscious of the impact of its capital spending plans on the affordability of electricity for its customers.

Ability to Connect New Load

The population in Oakville Hydro's service area is forecasted to increase by approximately 35% from 2011 to 2031 with the majority of the growth expected to occur in greenfield development areas. While growth has been slower than forecasted in the Best Planning Estimates of Population, Occupied Dwelling Units and Employment, 2011-2031 published by the Region of Halton in June 2011, Oakville Hydro anticipates growth of approximately 1% to 2% per year for over the planning horizon years with the majority of the growth occurring in greenfield areas not currently connected to Oakville Hydro's distribution system.

As detailed in Oakville Hydro's Renewable Energy Generation Investment Plan, provided as Appendix 4, there has been limited interest in FIT and microFIT generation projects in Oakville Hydro's service area and no renewable energy generation investments have been included in Oakville Hydro's DS Plan for the 2014 Test Year. However, industry requirements, policies and initiatives may change in the future and these changes may impact Oakville Hydro's plans involving the connection of renewable generation in the future.

Capital Asset Categories

Oakville Hydro's assets are traditionally divided into three categories; distribution plant, general plant and other capital assets. Distribution plant includes assets such as high voltage transformation, Municipal Transformer Station and substation buildings, poles, conductors, overhead and underground electricity distribution infrastructure, transformers, meters and substation equipment. General plant includes assets such as office building, office furniture, transportation equipment; information technology, computer equipment and software, general equipment, and tools. Other Plant includes capital leases. In accordance with the DS Plan Filing Requirements, Oakville Hydro has grouped its capital expenditures into the four investment categories defined in Table 1 of the DS Plan Filing Requirements.

System Access

System access investments are modifications to a distribution system that a distributor is obligated to perform to provide customers with access to electricity services via the distribution system.

Investments in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system. Most frequently, investments relate to request by customers for connections or connection modifications, but also include requests from municipal authorities for a distributor to relocate system assets in order to accommodate infrastructure development or modifications. Consequently, investment budgets for this category can vary from one DS Plan to the next depending on business conditions. Historically, Oakville Hydro has had to make investments in this category, primarily as part of road widening projects, as the infrastructure in the Town of Oakville and Halton Region is being improved.

In the event that the project involves replacing a distribution system assets, there may also be asset life-cycle-related considerations to the extent that infrastructure is taken out of service prior to the end of its service life and new infrastructure is commissioned.

Investments in this category are considered mandatory and allocation of the associated capital expenditure is non-discretionary. Consequently, the level of capital spending in this category directly impacts the level of spending in the other three investment categories.

System Renewal Investments

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 reliable electricity services.

Investments in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis and the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. “failure”). Generally, the higher the risk of failure, the more important it becomes to replace or refurbish the asset(s).

A distributor’s discretion over the timing and priority of projects in this category may lessen over time, such as where assets with high consequence of failure are consistently operating outside applicable operating limits. On the other hand, a distributor may have considerable discretion over timing and priority, where deteriorating asset condition has little or no impact on performance, and the consequences in terms of the number of customers and criticality of service potentially affected by an asset failure are relatively low.

Investments in this category are considered non-mandatory. Therefore, allocation of capital investments is optimized based upon risk and value. Investments are optimized against other investments within this category and in the System Service category. Investments are assessed by weighing the probability of failure against the consequences, considering both risk and value and Oakville Hydro’s Capital Investment Objectives.

System Service Investments

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 customer electricity service requirements. Like the System Renewal Investments, the allocation of the capital budget to this investment category is dependent upon the strategic objective weighting assigned to the individual projects or programs in this category.

Investments in this category are driven by the distributor’s expectations that evolving customer use of the system may create system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor’s service delivery standards or objectives. Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures.

Investments in this category are considered discretionary. Therefore, the allocation of capital to investments within this category is required to be optimized based upon risk and value. Investments are assessed by weighing the probability of failure against the consequences, considering both risk and value and Oakville Hydro's Capital Investment Objectives.

General Plant Investments

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 fleet equipment, rolling stock and electronic devices and software used to support day to day business operations and improve the level of customer satisfaction.

Distributor discretion in relation to investments in this category can be relatively high in terms of both initiating a project and determining the priority and timing of project-related expenditures. Oakville Hydro's Information Technology Strategic Plan supports Oakville Hydro's strategic imperatives. A copy of Oakville Hydro's Information Technology Strategic Plan is provided as Appendix 6. Oakville Hydro's follows a very diligent process for assessing the need for capital investments in this category and looks for innovative ways to maintain its business and operational activities to provide its customers with a level of service that meets their expectations.

Investments in this category are considered non-mandatory. Therefore allocation of capital to investments within this category is required to be optimized based upon risk and value.

Material Capital Expenditures

A list of material capital expenditures by category, including a brief description of the projects and the total capital expenditures, for the 2014 Test Year are provided in Table 3, Material Capital Expenditures. The Regional Planning Process and the connection of Renewable

Generation have not had a material impact on Oakville Hydro's DS Plan for the 2014 Test Year.

Table 3, Material Capital Expenditures

Major Projects	2014
27.6kV Additions	$420,973
Distribution Meters / Wholesale Meter Upgrades	481,706
New Development / Services	1,016,068
Road Widening (Dependent on Road Work - No Hydro Control)	403,115
System Access	**2,321,862**
Alterations and Improvements for Load Transfer and System Security	1,028,655
Rebuild Overhead Distribution System	1,118,877
Rebuild Underground Distribution System	2,017,232
Substations	1,016,763
Supervisory Control and Communications	231,887
Transformer Replacements and Voltage Conversion	566,332
System Renewal	**5,979,745**
Information Technology	452,000
Rebuild Overhead Distribution System	100,000
Supervisory Control and Communications	36,899
Emergency Back-up Transformer	5,000,000
System Service	**5,588,899**
Buildings	341,615
Information Technology	1,897,210
Major Tools and Safety Equipment	93,333
Transportation	384,762
General Plant	**2,716,920**
Grand Total	**$16,607,427**

Regional Planning Process

As discussed earlier, it will take approximately four years to complete the province-wide transition to the Regional Planning Process. Oakville Hydro is not currently aware of specific requirements for investments related to regional planning, at this time, and has not included any investments related to regional planning in its DS Plan. However, the two regional planning groups that Oakville Hydro is a member of, have been identified as being a high priority for regional planning. Oakville Hydro has engaged Hydro One to enable it to gain insight on the current status of the Regional Planning Process as it applies to these two regional planning groups. In the event that Oakville Hydro is required to make material investments as a result of the regional planning process, it will use the appropriate rate adjustment mechanism to seek approval for the recovery of those costs.

As discussed previously, Hydro One provided an update on the status of Regional Planning on September 5, 2013. In its letter, Hydro One confirmed that the Regional Planning Process has not been initiated and a Regional Infrastructure Plan has not been developed within the GTA West region or the Burlington to Nanticoke Region. Hydro One expects that regional planning will be initiated in the fourth quarter of 2013.

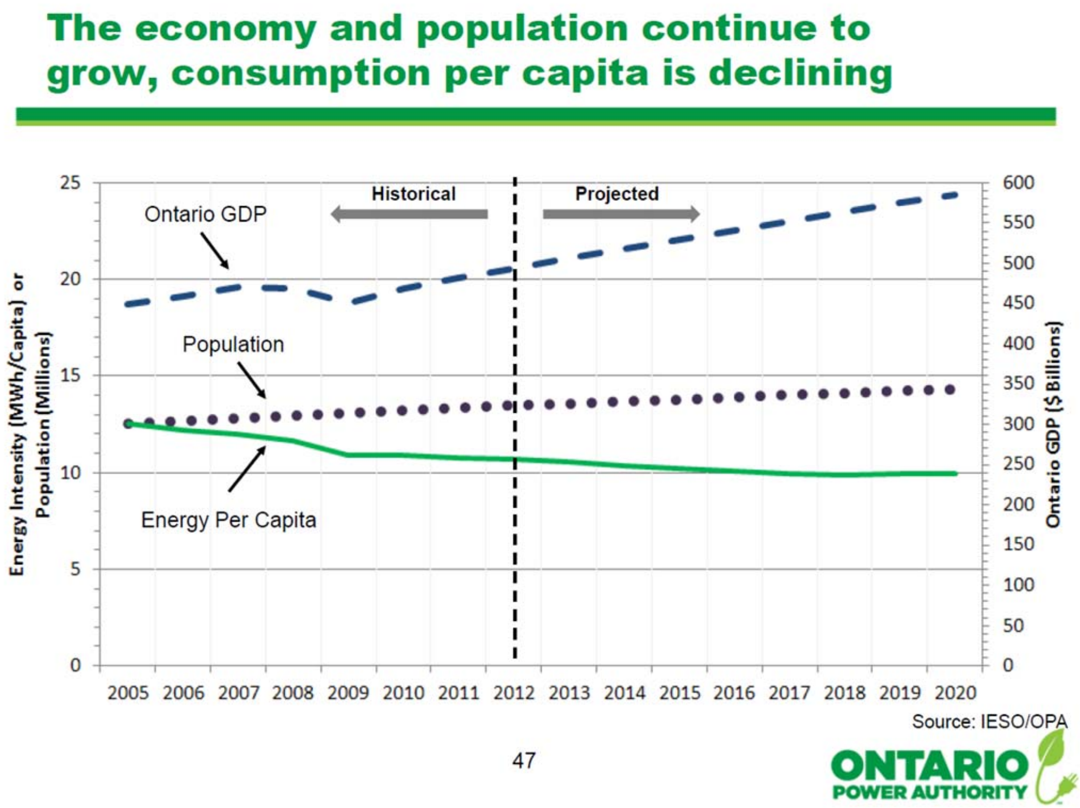
Customer Engagement

Oakville Hydro conducts a Residential customer satisfaction survey on an annual basis. As part of the customer satisfaction survey, Oakville Hydro asks its customers for their feedback on a number of areas including service reliability, outage management, electrical safety, value for money, cost effectiveness and affordability. In its 2013 customer satisfaction survey, Oakville Hydro's scores in these areas consistently met or exceeded both the Ontario average and the National average. Oakville Hydro's Capital Expenditure Plan balances the need to maintain a safe, reliable distribution system that is affordable to its customers while continuing to make investments to accommodate growth. Oakville Hydro's high scores in the areas of reliability and cost effectiveness are evidence of its ability to manage this balance. Oakville Hydro plans to enhance its customer satisfaction surveys in the future to enable it to better understand the expectations of its Residential customers.

In addition, Oakville Hydro's Key Account Manager engages commercial customers through site visits and seminars to address customer concerns, provide information to enable customers to enable them to make informed energy decisions and to enable them to run their businesses in a more cost effective manner. In recent years, customer engagement has focused primarily on the achievement of energy efficiencies and reducing costs. Oakville Hydro plans to improve its relationships with commercial and industrial customers through its key account manager.

Development of the Distribution System

Oakville Hydro is forecasting modest growth in its Residential and Small Business customer base during the five-year planning horizon. However, Oakville Hydro, like other jurisdictions, is forecasting that despite the fact that the economy and population continue to grow, consumption per capita is declining and that load growth will be modest. The graph below, prepared by the Ontario Power Authority illustrates the upward trends in economic and population in Ontario and the contrasting downward trend in average energy consumption per capita.



Oakville Hydro's Smart Grid Strategy, as provided in Appendix 5, is to grow and develop Oakville Hydro's distribution grid using a combination of good utility distribution practice coupled with emerging technologies & systems. Oakville Hydro's long term strategy is to evolve its operating distribution system and associated Information Technology ("IT") systems capabilities to align with its three over-arching Smart Grid goals listed below. Oakville Hydro plans to leverage the capabilities of current system assets to enhance future capabilities. For example, Oakville Hydro assessed the costs and outcome value to its customers of the integration of smart meter data into its Outage Management System ("OMS"). In addition, it will continue to make prudent asset management decisions around replacing selected end-of-life equipment and supporting communication infrastructure, with choices that align with this evolving strategy. Oakville Hydro will ensure that all Smart Grid projects align with Oakville Hydro's Investment Objectives, by integrating them into the capital project portfolio to be evaluated and prioritized as set out in the Exhibit 1.2, Asset Management Strategy. Oakville Hydro's Smart Grid over-arching goals for the ten-year planning horizon are as follows:

Customer Control

a) Enhance customer experience associated with control of energy usage.
b) Increase visibility on system outages
c) Connect renewable generation as required and take advantage of plug-in and hybrid vehicles as choice of transportation

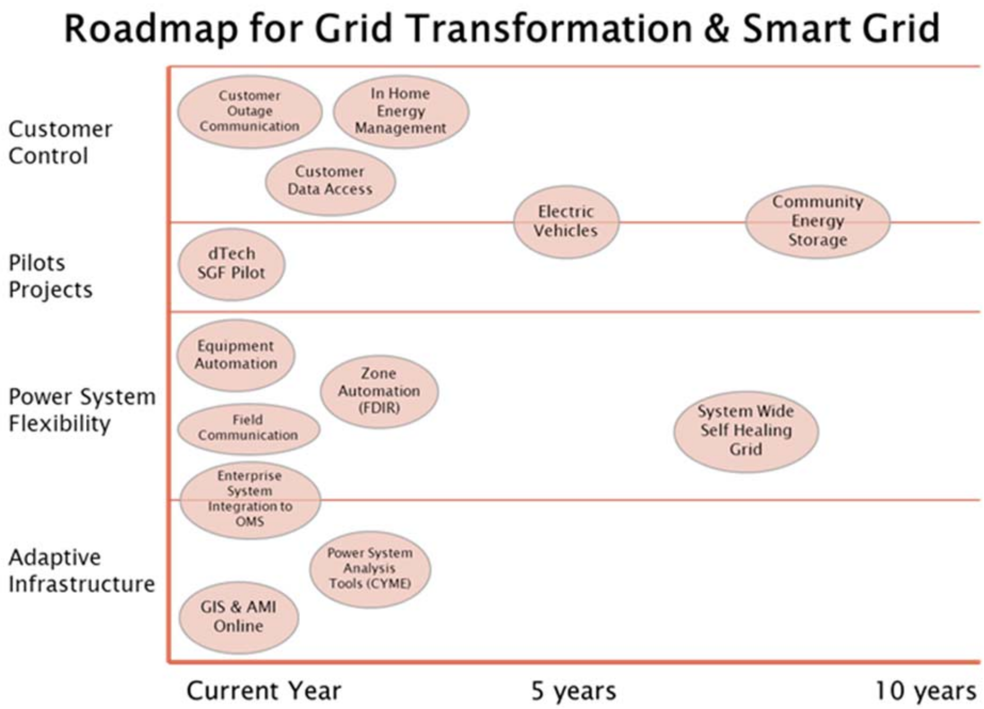
Power System Flexibility

a) Improve distribution system reliability, performance and responsiveness
b) Equip the existing distribution system to enable two-way flow of electricity
c) Improve operating efficiencies through distribution automation, e-mobile capabilities and IT system integration (e.g. Advanced Metering Infrastructure, Geographical Information System, and Outage Management System)

Adaptive Infrastructure

a) Improve power quality and energy efficiency using advanced system tools and controls, to monitor and reduce distribution losses
b) Enhance asset efficiency through system monitoring to fully utilize and extend life of existing assets

Over the next five years, Oakville Hydro will continue to reinforce the foundations of its distribution system (e.g. switching, monitoring and communications infrastructure) and enhance and integrate its operating and information systems in order to achieve these goals. These changes will involve continued enhancements of current engineering and operations technology platforms as well as planned integration into a new Outage Management System currently under development. A new level of sophisticated operational capabilities is evolving that will accept all forms of distributed generation and provide increased reliability through switching flexibility and automation of features such as self-healing distribution feeders. The following diagram provides more detailed near and long-term plans to operationalize this strategy.



The timing of Smart Grid investments will be, as mentioned, somewhat dependent on upgrades to Oakville Hydro's distribution system facilities through expansion or renewal. The rate of customers' adoption of renewable generation and consumer technologies will also have an impact on Oakville Hydro's anticipation of smart grid investments. The rate of customer adoption will depend on customer education and the perceived value of these smart grid technologies. The results of Oakville Hydro's 2013 customer satisfaction survey show that Oakville Hydro's customers have limited knowledge with respect to Smart Grid. Therefore, Oakville Hydro is in the process of developing communication materials for its customers on the Smart Grid and gathering information regarding their expectations for Smart Grid investments.

This will drive required customer focused investment.

Oakville Hydro is currently participating in an Ontario Smart Grid Fund, a program launched in 2011by the Ministry of Energy to support the growth and advancement of the province's electricity grid, demonstration pilot project in collaboration with a company by the name of dTechs. The dTechs MeterSuite is an advanced wireless metering system created to help distributors address grid management, line-loss reduction and power theft. The dTechs MeterSuite will find, immediately notify and direct Oakville Hydro to the location of atypical consumption. This includes power theft, unsafe high consumption and poor infrastructure areas (e.g. aged transformer equipment and poor distribution lines). This pilot project involved the deployment of 225 units in 2013 to cover 25% of Oakville Hydro's customer base.

Plug-in electric vehicles are starting to enter the market but adoption is slower than anticipated. These entrants, plus the potential for growth in electric public transportation, are expected to be longer term, but none-the-less, a significant aspect of evolving distribution systems. In 2013, Oakville Hydro partnered with Tim Hortons to install vehicle charging stations at two of its locations in the Town of Oakville. Oakville Hydro will continue to monitor the situation and work towards enabling their roll out through collaborative ventures. In the 2013 customer satisfaction survey, the number of customers that were "very interested" in purchasing an electric vehicle declined to 7% from 9% in 2012. This trend may change if oil prices become unstable and climb.

Automation and Innovation

Oakville Hydro has planned a number of projects in response to noted customer preferences, to take advantage of technology-based opportunities, improve operational efficiencies, improve asset management capabilities and study innovative processes, services business models or technologies. For those projects over Oakville Hydro's materiality level in the 2014 Test Year, additional information is provided in Appendix 7, Material Capital Project Templates.

Table 4, Automation and Innovation

Project Number	Project Name	Forecast ($)	Description
16-G2	27.6kV Air insulated switchgear upgrades	$379,340	Automated Restoration
16-U1	Gang-Operated Switch Replacement	$267,139	Remotely operated switches
14-61	Distribution Meters	$15,750	Data access - Zigbee Chips
14-64A1	Outage Management System Improvements	$300,000	Automated Restoration Capabilities
14-64A4	Power System analysis tool - CYME	$152,000	Load Management
14-64C1	Customer Communication improvements	$165,000	Customer Preference - Self Service Options
14-64D1	Microsoft Dynamic GP upgrade to GP2013	$123,000	Provides Asset Management Capabilities
14-64M1	Maximo Phase 3	$100,000	Asset Management

Capital Expenditure Planning Process Overview

Oakville Hydro's Asset Management process is the driver in determining Oakville Hydro's capital expenditures budget. The Asset Management process sets out processes for determining the necessary distribution system investments to ensure safe, reliable and cost-effective delivery of electricity to its customers. Oakville Hydro's Asset Management process accompanies this Exhibit as Appendix 1.

As discussed in the following section, System Capability Assessment for Renewable Energy Generation, Oakville Hydro has sufficient capacity to connect the forecasted future renewable generation projects. Therefore, Oakville Hydro's capital planning process does not currently include objectives for the connection of renewable generation facilities. Should there be a change to the forecast, Oakville Hydro will update its investment objectives and planning processes.

Although regional planning policies are currently not a formal part of Oakville Hydro's Asset Management Process, Oakville Hydro will re-evaluate and update its processes to include regional planning in the assessments of alternatives to relieving system capacity or operational constraints as Oakville Hydro's Regional Planning Process develops.

Oakville Hydro's Asset Management process identifies the capital expenditures required over a 20 year period based on its capital Investment Objectives discussed on page 30. Oakville Hydro's Capital Expenditure Plan identifies the capital projects required to meet the capital

Investment Objectives, showing the detailed current and following year projects, a high level cost for future years two to five, and statements identifying the direction from years six to twenty. The capital budget forecast for the 2013 Bridge Year and the 2014 Test Year is influenced by, among other factors, the highest priority capital requirements, notably - Oakville Hydro's capacity to finance capital projects and the impact on the cost to the customer. All proposed capital projects are assessed within the framework of their capital budget priority. A significant portion of Oakville Hydro's capital investments are customer or municipally driven and are outside of Oakville Hydro's control.

The capital budget is prepared annually by Management before the start of each fiscal year. It encompasses all capital requirements for the distribution system, substations, information technology hardware and software, vehicles and building costs.

Responsibilities

- The Finance department co-ordinates the development of the capital budget.
- Each department is responsible for preparing its respective capital budget; with the VP of Engineering and Operations and COO being responsible for the overall reasonableness of the capital budget expenditures.
- The President & CEO, COO and CFO review the capital budget in conjunction with the operating budget and identify any changes and challenge any alternatives. Once they are satisfied with the capital expenditures, they present and recommend the budget to the Audit and Finance Committee of the Board of Directors.
- The Finance and Audit Committee reviews the capital budget and may make recommendations to Management. Once the Finance and Audit Committee is in agreement, they make a recommendation to the Oakville Hydro Board for approval as part of the entire Business Plan.
- The Oakville Hydro Board of Directors has, on occasion, directed Management to revise a budget following consideration of year-end financial results or major changes in capital

project priorities.

- Each year, the COO, Vice President of Engineering and Operations is responsible for confirming in writing that the capital budget is prudent and satisfies the needs of the customers.
- The Finance Department monitors actual to planned spending on a monthly basis and reports to the Finance and Audit Committee on a quarterly basis.

The Budget is an important planning tool for Oakville Hydro. It puts capital and operational budgets into a common financial plan and allows for the evaluation of the total cost impact to the customer. The final document provides a comprehensive package of departmental budgets that collectively ensure that appropriate resources are designated for the various capital and operational needs of the utility for the coming year to meet customer expectations for service reliability and cost effectiveness.

Based on Oakville Hydro's distribution categories, below is a detailed description of the process followed in identifying capital expenditure needs.

Selection, Prioritization and Pacing of Projects

Distribution System Projects

In the initial phase of the capital budgeting process, Oakville Hydro's Engineering Department receives copies of all developer/site plan submissions from the Town of Oakville. Engineering is given the opportunity to comment on the submissions and determine how electrical demand will be met. Engineering also participates in the five-year plan review with the Town of Oakville, to keep abreast of future major developments.

In addition to incorporating development plans, input is received from internal Subject Matter Experts ("SMEs") incorporating risk areas in order to identify projects required to maintain the reliability and safety of the system. Condition assessments are also a criteria used to identify future project requirements. Asset condition is assessed and documented noting any urgent issues. In some cases simple maintenance tasks cannot mitigate these issues, prompting the need for a capital replacement project. In these situations a project is initiated, designed, planned and estimated to remedy the outstanding issues.

Oakville Hydro implemented and uses an Optimizer Software package as a systematic tool to assist in the planning and evaluation of its multi-year project portfolio and create a prioritized list of projects that is used as the basis for the capital budget. The optimization of future project portfolios allows Oakville Hydro to ensure that future capital costs are systematically applied to the appropriate areas of the system to mitigate risk and improve value. Future projects are evaluated by considering both their risk and probability of failure if not completed, and their value if completed. More details are provided in the Asset Management Process, filed as Appendix 1 to the DS Plan.

Fleet

The Operations Department reviews the status of all vehicles and the annual maintenance and repair costs and recommends the timing for replacements. Oakville Hydro currently uses an outside consultant who in consultation with the Director of Distribution Operations, determines fleet requirements, obtains quotes and makes recommendations to the Director.

Other

Justification for all other capital projects is provided by the relevant department and approved by the appropriate level of management. Expenditures, where the cost of the individual item is greater than $1,000 are capitalized, and those less the $1,000 are expensed.

Customer Engagement

Over the past three years, Oakville Hydro has and engaged a third party to conduct customer satisfaction surveys. These customer satisfaction surveys provide information that supports decisions surrounding the improvement of system reliability and customer service. The survey asks customers questions on a wide range of topics, including: overall satisfaction with Oakville Hydro, reliability, trust, customer service, outages, billing and corporate image. In addition, Oakville Hydro has a key account manager to maintain a close relationship with commercial and industrial customers to enable Oakville Hydro to understand the needs and expectations of this customer class.

Oakville Hydro involves customers in special projects where customer input, education and opinion is requested for valued consideration. For example, in 2010 Oakville Hydro held a public session inviting the public to become engaged in the proposal to build the Glenorchy Municipal Transformer Station required to service North Oakville.

Capital Budget Attestation

As part of the budget approval process, the COO, Vice President Engineering and Operations formally confirms that the Capital Investment Plan and associated Operations and Maintenance Programs are adequate to maintain Oakville Hydro's electricity distribution system based on customer requirements. In addition, confirmation is provided that the plan aligns with the goals of prudent Asset Management and has been developed and prioritized to ensure obligations to stakeholders are met and regulatory compliance is assured. This attestation is provided to Oakville Hydro's Board of Directors.

System Capability Assessment for Renewable Energy Generation

Section 5.1.4.2 of the DS Plan Filing Requirements requires that distributors submit information to the Ontario Power Authority (the "OPA") in relation to the Renewable Energy Generation investments identified in their DS Plan. (The OPA is expected to provide a letter of comment with regards to these plans for inclusion in a distributor's cost of service application). Oakville Hydro's renewable energy generation investment plan forms part of its overall Distribution System Plan. Oakville Hydro's Renewable Energy Generation Investment Plan has been created as a separate document for the purpose of the OPA's review and letter of comment and provided as Appendix 4, Renewable Energy Generation Plan (including a copy of the OPA's letter of comment with regards to Oakville Hydro's Renewable Energy Generation Investment Plan) and summarized in the following paragraphs.

The Renewable Energy Generation Investment Plan assesses the state of Oakville Hydro's existing distribution system, studies the current renewable connected generation and near-term growth forecast, develops a strategy to accommodate the predicted renewable generation growth and describes Oakville Hydro's future Renewable Generation expenditures from 2014 through 2018.

The OPA launched the Feed-In Tariff ("FIT") program in 2009. The FIT/microFIT program generated modest interest in Oakville Hydro's service area. Oakville Hydro's connected renewable generation is 0.49 MW for FIT programs. Currently there are three FIT projects and 32 microFIT projects which have been connected. There are seven FIT applications in Oakville Hydro's territory waiting for a contract with the OPA.

Oakville Hydro's distribution system is a robust, integrated network throughout the Town of Oakville. Adequate planning and proactive infrastructure projects have made the distribution network well-equipped to handle forecasted renewable generation. However, there are two Hydro One owned transformer stations namely, Palermo and Trafalgar where there are short circuit capacity restrictions related to the connection of renewable generation, within the upstream transmission system. However, the remaining stations have sufficient short-circuit capacity to accommodate the type of distributed generation that Oakville Hydro has seen so far. Most of the renewable energy projects proposed in Oakville Hydro's service area are inverter-based with limited fault contribution to Oakville Hydro's distribution system. It is unlikely that the fault contribution from the anticipated distributed generation will cause Hydro One owned transformer stations to reach the short-circuit capacity limits.

Based on Oakville Hydro's 2011 to 2013 FIT/microFIT data and the future assumptions, it is for renewable energy indicate that Oakville Hydro is ready to connect future renewable generation projects.

Consequently, Oakville Hydro has not included any capital expenditures related to renewable energy generation in its Distribution System Plan. In addition, there are no additional OM&A costs proposed related to renewable energy generation as Oakville Hydro is able to use existing staff to process microFIT/FIT applications and all the related requirements that currently exist.

Capital Expenditure Summary

Oakville Hydro has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through careful capital spending. Capital additions for material 2014 Test Year projects are provided in Appendix 7, Material Capital Project Templates. An overview of Oakville Hydro's capital additions from 2009 to 2018 follows below in Table 5.

Chapter 5 of the DS Plan Filing Requirements issued by the Board on March 28, 2013 requires that a distributor's investment projects and activities be grouped for filing purposes into one of four investment categories: system access, system renewal, system service or general plant. Oakville Hydro has grouped actual expenditures for the Historical Years and forecasted expenditures for the 2013 Bridge Year and the 2014 Test Year in the Board's investment categories.

Distributors are also requested to provide summary information for the last five years prior to the test year as well as historical "previous plan" data if a plan had previously been filed with the Board. Oakville Hydro filed plans with the Board for the year 2010 as part of its 2010 Cost of Service Application. Oakville Hydro has not filed previous plans for the years 2009, 2011, 2012 and 2013 with the Board. Therefore, Oakville Hydro has included it internal capital plans in Table 5.

Oakville Hydro does not have historical capital planning detail broken into the Board's investment categories: System Access, System Renewal, System Service and General Plant. Therefore, Oakville Hydro has provided capital planning data based on its total capital expenditures budget.

Table 5 Capital Expenditure Summary

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2014*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access		5,782	--		3,307	--		29,215	--		3,090	--	3,291	3,822	16.1%	2,322	2,130	2,448	2,497	2,639
System Renewal		13,001	--		11,146	--		6,939	--		7,571	--	5,573	5,535	-0.7%	5,980	5,436	5,505	5,599	5,599
System Service		1,449	--		916	--		838	--		11,351	--	79	201	155.0%	5,589	559	581	605	629
General Plant		2,535	--		1,247	--		3,055	--		1,984	--	2,549	2,137	-16.2%	2,717	2,126	2,866	2,052	2,063
TOTAL EXPENDITURE	18,232	22,767	24.9%	14,721	16,615	12.9%	29,024	40,046	38.0%	13,562	23,996	76.9%	11,493	11,695	1.8%	16,607	10,251	11,401	10,752	10,931
System O&M	n/a	$ 5,852	--	$ 6,135	$ 5,568	-9.2%	n/a	$ 6,936	--	n/a	$ 7,308	--	$ 10,140	$ 10,394	2.5%	$10,758	n/a	n/a	n/a	n/a

NORMALIZED CAPITAL EXPENDITURES (EXCLUDING GLENORCHY MTS, SMART METERS, 3rd PARTY IRU)

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2009			2010			2011			2012			2013			2014	2015	2016	2017	2018
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
System Access	-	4,967	--	2,372	3,307	39.4%	-	6,354	--	-	2,931	--	3,291	3,822	16.1%	2,322	2,130	2,448	2,497	2,639
System Renewal	-	13,001	--	8,662	11,146	28.7%	-	6,939	--	-	7,571	--	5,573	5,535	-0.7%	5,980	5,436	5,505	5,599	5,599
System Service	-	1,449	--	781	916	17.2%	-	783	--	-	1,232	--	79	201	155.0%	589	559	581	605	629
General Plant	-	1,635	--	2,906	1,247	-57.1%	-	3,055	--	-	1,984	--	2,549	2,137	-16.2%	1,979	2,126	2,380	2,052	2,063
TOTAL NORMALIZED EXPENDITURE	18,232	21,052	15.5%	14,721	16,615	12.9%	17,938	17,132	-4.5%	13,562	13,718	1.1%	11,493	11,695	1.8%	10,869	10,251	10,915	10,752	10,931
Glenorchy MTS/Emergency Back-up Transformer	-	-		-	-		9,186	22,861		-	159		-	-		5,000	-	-	-	-
Smart Meters	-	-		-	-		1,900	54		-	10,119		-	-		-	-	-	-	-
New Customer Information System	-	-		-	-		-	-		-	-		-	-		-	-	486	-	-
Remaining 3rd Tranche CDM Activities	-	1,715		-	-		-	-		-	-		-	-		-	-	-	-	-
3rd Party IRU	-	-		-	-		-	-		-	-		-	-		738	-	-	-	-
TOTAL EXPENDITURE	18,232	22,767	24.9%	14,721	16,615	12.9%	29,024	40,046	38.0%	13,562	23,996	76.9%	11,493	11,695	1.8%	16,607	10,251	11,401	10,752	10,931

Table 5 Capital Expenditure Summary, Continued

CATEGORY	Forecast Period (planned)				
	2014	2015	2016	2017	2018
	$ '000				
System Access	2,322	2,130	2,448	2,497	2,639
System Renewal	5,980	5,436	5,505	5,599	5,599
System Service	5,589	559	581	605	629
General Plant	2,717	2,126	2,866	2,052	2,063
TOTAL EXPENDITURE	16,607	10,251	11,401	10,752	10,931
System O&M	$10,758	n/a	n/a	n/a	n/a

NORMALIZED CAPITAL EXPENDITURES (EXCLUDING GLENORCHY MTS, SMART METERS, 3rd PARTY IRU)

CATEGORY	Forecast Period (planned)				
	2014	2015	2016	2017	2018
	$ '000				
System Access	2,322	2,130	2,448	2,497	2,639
System Renewal	5,980	5,436	5,505	5,599	5,599
System Service	589	559	581	605	629
General Plant	1,979	2,126	2,380	2,052	2,063
TOTAL NORMALIZED EXPENDITURE	10,869	10,251	10,915	10,752	10,931
Glenorchy MTS/Emergency Back-up Transformer	5,000	-	-	-	-
Smart Meters	-	-	-	-	-
New Customer Information System	-	-	486	-	-
CDM Activities	-	-	-	-	-
3rd Party IRU	738	-	-	-	-
TOTAL EXPENDITURE	16,607	10,251	11,401	10,752	10,931

Explanatory Notes on Variance in Capital Expenditure Summary

Shifts in Forecast versus Historical Budgets by Category

Oakville Hydro does not have historical capital planning detail broken into the Board's investment categories: System Access, System Renewal, System Service and General Plant. Therefore, Oakville Hydro has provided notes on shifts by category for the 2013 to 2018 forecast years only.

System Access:

Spending in 2013 is significantly higher than that expected in 2014 through 2018. The 2013 Test Year includes two large system access projects, namely the construction of feeders for the new Oakville Hospital which is currently under construction and expected to be complete at the end of 2015 and the connection of Milton Hydro Electricity Distribution Inc. as an embedded distributor at the Glenorchy Municipal Transformer Station. For the forecast period 2014 through 2018 System Access projects are expected to be between $2.1M and $2.6M. Road widening projects are expected to decrease from 2014 forecasted levels due to an anticipated decline in municipal, regional and provincial projects. Future expenditures for new development/services and meters are expected to increase moderately.

System Renewal:

System access investments are investments in the replacement or refurbishment of the distribution system to extend the original service life of the assets. Expenditures on System Renewal projects are expected to be in the $5.5M to $6.0M range from 2013 to 2018.

System Service:

This category typically includes SCADA enhancements and upgrades, switching improvements and installations at various locations in Oakville, installation of remote fault indicators and repeater site upgrades. In 2013, resources normally allocated to these types of projects are expected to be used for the two large system access projects referenced above -

the construction of feeders to service the new Oakville Regional Hospital and Milton Hydro. Once completed, spending in the system service category is expected to increase and remain relatively consistent through 2014 through 2018.

General Plant:

General Plant projects are forecasted to be in the $2.1M range for the 2013 Bridge Year and the 2014 Test Year with normalized expenditures decreasing to a range between $2.0M and $2.4M from 2015 to 2018. Oakville Hydro has made, and plans to make, system investments in information technology in 2013 to 2014 (CMMS, GIS, Health and Safety). Although upgrades and improvements to these systems are expected in 2015 to 2018, they will not be of the same magnitude as the initial systems cost. The increase in General Plant in 2016 is due to the expected implementation of a new Customer Information System. Expenditures for vehicles, tools and leasehold improvements are expected to be consistent from 2013 onwards.

Notes on Year over Year Plan versus Actual Variances for Total Expenditures

2009 Planned versus 2009 Actual

In 2009, capital additions excluding CDM activities were $21.0M, an increase of $2.8M as compared to the 2009 planned capital additions of $18.2M. The increase in capital additions was primarily due to an increase in new development and services of $1.3M, and increase of $1.0M in the investments in substations as a result of the construction of the new Arkendo Municipal Substation rather than the planned decommissioning of an existing Municipal Substation and the enhancement of the SCADA system at a cost of $0.8M.

2010 Board Approved versus 2010 Actual

In 2010, capital additions were $16.6M, an increase of $1.9M as compared to the 2010 Cost of Service application which projected capital additions of $14.7M. The increase in capital additions were primarily due to increased spending on projects that were beyond the control of Oakville Hydro. Actual expenditures for 27.6kV additions, new development and services, unanticipated road widening and substation equipment refurbishments were $1.3M higher than budgeted. In addition, Oakville Hydro added a transformer replacement and voltage conversion in the Woodhaven Park area to the 2010 capital plan at a cost of $0.4M. Although this project was not in the 2010 capital plan, conditions were such that the replacement was required in 2010.

2011 Plan versus 2011 Actual

The 2011 actuals, excluding the Glenorchy Municipal Transformer Station and Smart Meters, were $0.8M or 5% lower than Oakville Hydro's 2011 capital plan. The decrease versus budgeted capital additions was due to lower spending on Information Technology projects, replacement of fewer vehicles than anticipated, and lower spending on the Rear Lot Distribution Projects, a multi-year project to remove high voltage lines from rear lot areas. This was partially offset by the costs associated with the re-roofing and renovation of Oakville Hydro's head office at 861 Redwood Square and higher than anticipated cost of the feeders from the Glenorchy Municipal Transformer Station due to higher than predicted ground water flows present on the site which increased the cost and complexity of the construction work.

2012 Plan versus 2012 Actual

Total actual spending in 2012, excluding the Glenorchy Municipal Transformer Station and Smart Meters, was $0.2M or 1% higher than Oakville Hydro's 2012 capital expenditure plan. The difference between planned capital expenditures and actual capital expenditures in 2012 was not material.

Notes on Plan versus Actual Trends for Individual Expenditure Categories

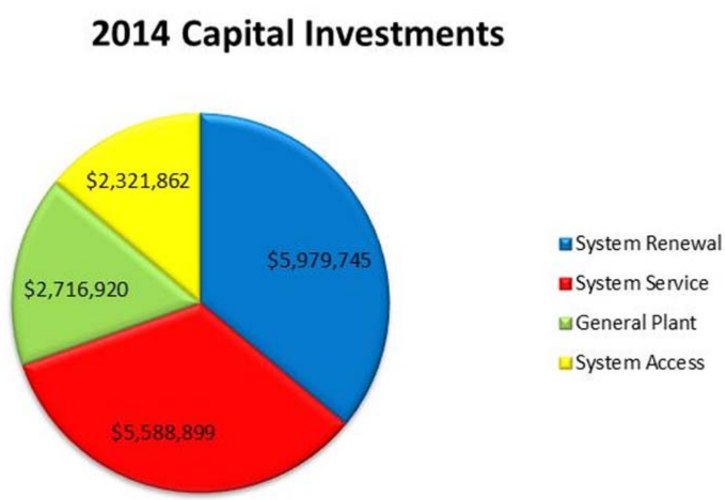
As noted previously, Oakville Hydro has provided its total capital budget for the 2009 to 2012 historical years. Oakville Hydro is not providing notes on plan versus actual trends for individual expenditure categories; instead, Oakville Hydro is providing notes on plan versus actual trends for total expenditures.

As discussed previously, the variance between planned capital expenditures and actual capital was $2.8M in 2009, $1.9M in 2010, ($0.8M) in 2011 and $0.2M in 2012. This reduction in the variance between planned and actual capital spending is evidence that Oakville Hydro's planning process has evolved in recent years. Its new Asset Management Process has enabled it to more accurately budget its capital investment requirements. This process is continuing to evolve to provide for better planning over a longer term planning horizon.

Justifying Capital Expenditures – 2014 Test Year

Overall Plan

As stated in the RRFE Report, good planning is necessary to ensure that the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. Consistent with this outcome based approach, Oakville Hydro's Capital Expenditure Plan is designed to provide a distribution system that is efficient, reliable, sustainable, and provides value for customers. Oakville Hydro's historical and planned capital investments are summarized by category in the following chart.



Impact of Capital Investments on Operating and Maintenance Costs

As noted in the individual project details in Appendix 7 - Material Capital Project Templates, there are a number of capital projects that will reduce operating and maintenance costs. These reductions have enabled Oakville Hydro to refine the patrol and maintenance process to ensure that minimum requirements are met, and that follow up maintenance is completed to mitigate the need for capital expenditures to replace equipment prematurely due to failures with existing staff. Advantages that have been realized include:

New or Improved Processes:

- Increased quality and quantity of data collected during patrols of distribution system assets
- Increased infrared thermography to include local feeders instead of just express feeders.
- Increased radio frequency detection to include both local and express feeders.
- New underground cable testing techniques in order to accurately capture condition.
- New process for the investigation of underground cable, splice and device failures.
- New process for rigid washing cycle for commercial vaults to include a washing in the spring to mitigate salt deposited over the winter months, and washing in the fall to mitigate organic debris deposited over the fall months.

Cost Savings:

- Increased interval between maintenance activities for padmount switches – from three to six years.
- New processes to track underground cable failures to allow for faster identification and restoration in order to reduce administrative costs and improve customer satisfaction.
- Installed polymer insulators to reduce failures due to pollution-allowing for the discontinuation of insulator washing.
- Extended the testing and treatment maintenance of wood poles from a three year cycle to a six year cycle.

Capital Expenditures Drivers

The main drivers of capital expenditures are summarized below. As previously noted, investments related to renewable energy generation are not currently a driver of capital investments in Oakville Hydro's service area. The calculated remaining capacity and the projected demand for renewable energy indicate that Oakville Hydro is ready to connect future renewable generation projects. Further details are provided in Appendix 4, Renewable Energy Generation Investments. Therefore, Oakville Hydro has not included any capital expenditures related to renewable energy generation in its DS Plan.

Investments related to System Access are expected to be lower in the near term due to a reduction in road widening projects in the Town of Oakville. As discussed in the section entitled Capital Asset Categories, capital investments are allocated to the remaining investment categories based upon the optimization of risk and value.

Table 7, Summary of Capital expenditure drivers

	System Access	System Renewal	System Service	General Plant
Drivers	New Customer Connections	Equipment Failure	Safety Improvements	Equipment Failure
	Distribution Meters	Equipment Damage	New Technological Advancements	Equipment Damage
	Municipal Road Changes	Reliability Improvemnts	Operational Savings	New Technological Advancements
	Modifications to Connect New Customers	Operational Savings	Reliability Improvements	Operational Savings

Material Investments

Oakville Hydro's 2014 capital projects above its materiality level of $180,000 are listed in Table 8, Material Capital Projects – 2014 Test Year, below and summarized in the following paragraphs. Project details for individual projects over Oakville Hydro's materiality level are also provided in Appendix 7 – Material Capital Project Templates and, in accordance with the DS Plan Filing Requirements, include the following (where applicable):

- **General Information**
- **Evaluation Criteria and Information Requirements**
- **Category Specific Requirements**

Table 8, Material Capital Projects – 2014 Test Year

Project #	Description	System Type	Total Project Cost	Contributed Capital	Oakville Hydro Project Cost
05-N	Onsite Emergency Back-up Transformer for Glenorchy MTS	System Service	$5,000,000	$0	$5,000,000
14-64A1	SCADA Enhancements in Loadflow, Contingency Analysis, FDIR	System Service	300,000	0	300,000
16-G2	27.6kV Air insulated switchgear upgrades to G&W	System Renewal	379,340	0	379,340
16-U1	Gang-Op Switch Replacement Program	System Renewal	267,139	0	267,139
05-P2	Power Transformer Replacement Program	System Renewal	268,190	0	268,190
05-Q2	Victoria MS Low Voltage Breaker Replacement Program	System Renewal	547,715	0	547,715
46-A	Replace Overhead Assets on John Street	System Renewal	207,270	0	207,270
46-B	Replace Overhead Assets on Queen Mary, Bond and Chisholm	System Renewal	358,919	0	358,919
46-C	Replace Overhead Assets on Robinson St.	System Renewal	458,981	0	458,981
45-A	Vault Transformer Replacements	System Renewal	316,241	0	316,241
45-D	Poletran Removals and Replace U/G Assets Various Locations	System Renewal	292,164	0	292,164
45-Q	Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion	System Renewal	385,205	0	385,205
45-X	Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln	System Renewal	184,665	0	184,665
42-B	Live front Padmount Transformer Replacements	System Renewal	275,730	0	275,730
44-H	27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403	System Access	420,973	0	420,973
14-50C	New Development Investment	System Access	2,280,508	1,856,780	423,729
14-54	New General Services	System Access	598,945	247,341	351,604
14-61	Distribution Meters	System Access	481,706	0	481,706
15-E	North Service Rd Widening, 8th Line to Iroquois Shore Rd	System Access	244,991	91,191	153,800
15-I	Road Widening TBD	System Access	309,752	106,518	203,234
14-62	2014 Fleet	General Plant	384,762	0	384,762
14-64D	ERP - GP & Business Intelligence	General Plant	203,000	0	203,000
14-64F	IT Infrastructure	General Plant	420,000	0	420,000
LSHOLD	HVAC upgrade - 5 year replacement program	General Plant	230,000	0	230,000
	3rd Party Indefeasible Right of Use	General Plant	738,210	0	738,210
	Material Capital Projects		**15,554,406**	**2,301,829**	**13,252,577**
	Other Non-Material Total		**4,352,301**	**997,452**	**3,354,850**
	Total		**$19,906,708**	**$3,299,281**	**$16,607,427**

System Access

The system access investment category includes the capital investments associated with the connection of new customers and distribution meters in Oakville Hydro's service area. Seven projects have been identified for the 2014 Test Year. These projects are non-discretionary.

Project 15-E Widening of North Service Road and 15-I Miscellaneous Road Widening

Oakville Hydro's 2014 Capital Expenditure Plan includes the costs associated with the widening of North Service Road and other miscellaneous road widening projects. North Service Road will be widened from the existing two lanes into four lanes from 8th Line to Iroquois Shore Rd. This represents one km of roadway and at least 20 new poles. This project will require relocation of poles and associated distribution equipment to make room for the new lanes.

14-50C New Development Investment and 14-54 New General Services

Oakville Hydro's 2014 Capital Expenditure Plan includes the estimated costs associated with the connection of new residential and commercial customers.

14-61 Distribution Meters

Oakville Hydro's 2014 Capital Expenditure Plan includes the estimated costs associated with distribution meters. This project includes the costs of new residential meters equipped with Zigbee to facilitate real-time access to smart meter data, multi-residential meters, commercial meters, and a new Tower Gateway Base ("TGB") station to support increased smart meter data collection.

44-H Additional 27.6kV feeder

Oakville Hydro's 2014 Capital Expenditure Plan includes the costs associated with the addition of an additional 27.6kV feeder on Upper Middle Road E, from Ninth Line to Highway #403, to support load growth in the Winston Business Park. This will also support future load growth in the next phase of new development in the area (Winston Park West).

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.

Project 16-G2 27.6kV Air Insulated Switchgear Upgrade Program

Oakville Hydro's 2014 Capital Expenditure Plan includes the costs associated with the replacement of 27.6kV air insulated style padmount switchgear. The 27.6kV air insulated style padmount switchgear is at a risk due to contamination and flashovers. The insulators inside of these switchgears are susceptible to salt spray contamination during the winter. When located in a high traffic area, the contamination builds up and can cause flashovers. In these cases the switchgear needs to be removed and either refurbished or scrapped depending on the level of damage. If replaced with deadfront switchgear, the salt spray does not affect the unit, mitigating the risk of the flashovers. The existing switchgear is also subject to accelerated aging due to adverse weather conditions and road salt. The new switchgears are easier to operate, have an electronic trip and do not require fuse replacements, and dry ice cleaning is required only every six years.

Project 16-U1 Gang-Operated Switch Replacement Program

Vacuum gang-operated switches tend to fail without warning, and there is little to no maintenance that can be performed in order to keep them in working order. Upon failure they are replaced with newer style remote operated switches. In order to mitigate this risk, Oakville Hydro has implemented a gang-operated switch replacement program to prioritize the replacement of the switches based upon the risk of failure. Replacement of these switches before failure reduces the risk of outages, customer or employee injury and fire, and improves reliability and performance measures.

Project 42-B Livefront Transformer Replacement Program

Oakville Hydro has phased these transformers out over time and only a handful remains in the field with no straight replacement stock available. The units are typically installed without proper foundations causing issues during replacement with newer units that require foundations. On average these units are 40 years old. The 2014 Capital Expenditure Plan provides for the replacement of the remaining livefront transformers at 1027 Speers Road. The replacement of these transformers reduces the risk of outages, equipment failures and employee injury, while protecting the environment from the release of toxic materials and improving reliability and performance.

Project 45-A Vault Transformer Replacement Program

These transformers typically service residential apartment buildings or commercial plazas. There are numerous instances where current limiting style fuses are installed that are difficult to operate and replace safely. Many of these locations are difficult to access and pose safety issues due to open air live parts. The replacement of these transformers reduces the risk of outages, equipment failures and employee injury, while protecting the environment from the release of toxic materials and improving reliability and performance.

Project 45-Q Replace Underground and Overhead Assets in Colchester Area and Project 45-X Replace Underground and Overhead Assets in Willowbrook Area

A number of areas with aging underground distribution have been identified for replacement including the Colchester area and Willowbrook areas. Typically in these older areas the cables are direct buried, causing replacement challenges. If one of these cables were to fail, the fault will have to be located, and excavated. Once the fault is isolated, a splice can be added in order to use the cable again. Rebuilding of these areas with ducts will provide a means to remove the cables when they are failing. These areas typically have non-vented bushing inserts and elbows which can allow flashovers to occur when switching takes place. The replacement of these assets reduces the risk of outages and equipment failures, reduces the risk of employee and customer injury, protects the environment from the release of toxic materials and improves reliability performance.

Project 46-A Replace Overhead Assets on John Street Project

Project 46-B Replace Overhead Assets in Queen Mary Area

The John Street and Queen Mary areas have been patrolled and the assets have been identified in poor and degrading condition. The replacement of these assets reduces the risk of outages and equipment failures, reduces the risk of employee injury, protects the environment from the release of toxic materials and improves reliability performance.

05-P2 Power Transformer Replacement Program

Oakville Hydro plans to replace Power Transformer Loc-B at Woodhaven Municipal Station, which is the oldest power transformer in Oakville Hydro's distribution system, unless another deteriorates rapidly resulting in a lower health index. The replacement of these assets reduces the risk of outages and equipment failures. Deferral of the replacement until failure results in increased maintenance costs and leads to transfer of the financial costs to future customers as well as the increased risk of significant outages. Substation power transformers are especially critical due to their role in supplying hundreds of customer in the surrounding area.

Project 05-Q2 Victoria Municipal Substation Low Voltage Breaker Replacement Program

Oakville Hydro plans to replace the Low Voltage Breaker lineup at Victoria MS, which is the oldest Low Voltage Breaker lineup in Oakville Hydro's distribution system, unless there is a rapid deterioration or failure of another low voltage breaker. The replacement of these breakers reduces the risk of outages and equipment failures. Substation breakers are especially critical due to their role in supplying power to hundreds of customers per feeder.

System Service

Project 05-N On-site Emergency Back-up Transformer for Glenorchy Municipal Transformer Station

On September 17, 2010, Oakville Hydro filed an ICM application, EB-2010-0104 which included a request for the recovery of the capital costs associated with the design and construction of Oakville Hydro's Glenorchy Municipal Transformer Station. On March 14, 2011, the Board approved Oakville Hydro's application and the associated rate rider. In 2011, Oakville Hydro completed the project of building its Glenorchy Municipal Transformer Station in order to service the customers of Oakville.

In July of 2011, this municipal transformer station realized a peak load level of 44MW supplied to the north-central area of Oakville. In August 2013, Milton Hydro connected to Oakville Hydro's distribution system and became an embedded distributor. With the connection of Milton Hydro, the transformer station's utilisation is increased by 6 MW from Milton Hydro. Further load will be added to the Glenorchy Municipal Transformer Station when the new Regional hospital is connected to the distribution system in late 2015. These customers will be Oakville Hydro's two largest customers and the criticality of maintaining reliable service to these two customers is increasing.

The acquisition of the emergency back-up transformer could also benefit the Board's Regional Planning process in that it could be made available to other transmitters or distributors in the same geographical area. In addition, as previously discussed, Oakville Hydro is unique in that it is fed by three separate transmission supplies and Oakville Hydro is often called upon by Hydro One to perform short-term load transfers among its distribution stations to alleviate capacity constraints within the region. A prolonged failure at the Glenorchy Municipal Transformer Station would severely compromise Oakville Hydro's ability to assist Hydro One which may result in greater challenges in the region.

The Glenorchy Municipal Transformer Station does not have an on-site emergency back-up transformer for use in event of a failure. Therefore, Oakville Hydro believes it is imperative and critical to the customers it serves to have this capability on hand. Oakville Hydro has included the estimated cost of $5.0 M in its capital expenditure plan in the 2014 Test Year. Table 9, Components of the On-site Emergency back-up Transformer, provides a breakdown of the costs by component.

Table 9, Components of the On-site Emergency Back-up Transformer

Type	CGAAP ($)
Equipment	3.6M
Construction	1.0M
Design	0.2M
Commissioning	0.2M
Total Costs	5.0M

In preparing its DS Plan, Oakville Hydro explored a number of alternatives for the acquisition of an emergency back-up transformer for the Glenorchy Municipal Transformer Station as discussed below.

ALTERNATIVES

Collaboration with Hydro One

In keeping with the Board's focus on regional planning, Oakville Hydro approached Hydro One to determine whether there was an opportunity to share their inventory of spare transformers with Oakville Hydro. On June 7, 2012 Hydro One advised Oakville Hydro that they were not interested in sharing their back-up transformers. Although Hydro One had been approached by several distributors to discuss the feasibility of entering into an arrangement to share backup transformers, including Hydro One Brampton, Hydro One advised that they had concerns regarding "numerous procurement, logistical, accounting and pricing issues" associated with the sharing of back-up transformers. On August 19, 2013, Oakville Hydro contacted Hydro One who confirmed that its position of not being able to provide an emergency back-up transformer had not changed.

Collaboration with Neighbouring Electricity Distributors

Oakville Hydro contacted PowerStream, its closest neighbouring distributor with a back-up transformer in its inventory that meets the design specifications of the Glenorchy Municipal Transformer Station, to explore the potential for sharing the costs associated with the ownership of a back-up transformer. On November 12, 2012, PowerStream advised Oakville Hydro that they would be interested in sharing their back-up transformer with Oakville Hydro. At that time, PowerStream advised that they would require an annual standby fee for potential access and a monthly fee to lease the transformer if Oakville Hydro required the use of the back-up transformer. Costs would continue until the spare or a replacement unit was returned to the pool.

Having received this response, Oakville Hydro approached ABB (the transformer supplier) for information on the feasibility of transporting the PowerStream back-up transformer from their Greenwood Transformer Station where it is stored, to Oakville Hydro's Glenorchy Municipal Transformer Station in the event of a failure. ABB supplied and installed both of the existing power transformers at Glenorchy Municipal Transformer Station, and also supplied both the spare and in-service transformers to PowerStream. In addition, ABB has prepared a preparedness plan for PowerStream that details how their spare transformer will be mobilized to each of their transformer stations if required in the event of a failure. Given this experience, Oakville Hydro believes that ABB is well-equipped with the technical expertise to advise Oakville Hydro on the feasibility of using the PowerStream back-up transformer.

On February 14, 2013, ABB provided Oakville Hydro with their findings regarding the feasibility of Oakville Hydro using the PowerStream back-up transformer. ABB found that, although it is possible to transport the PowerStream spare transformer to Glenorchy Municipal Transformer Station, it would be both complicated and time consuming. Successful transportation to site depends on railcar arrangements, use of the Hydro One's rail siding near the Trafalgar Transformer Station in Oakville and road route surveys. In addition, there is a half load restriction from March until May on some of the roadways over which the back-up transformer would be required to travel in order to reach the Glenorchy Municipal Transformer Station. A further complication would be the time required to transport and install PowerStream's back-up transformer to the Glenorchy Municipal Transformer Station which ABB has estimated to be between 35 and 40 days.

The half-load restrictions would present a significant service risk to the customers serviced from Glenorchy Municipal Transformer Station during the period in which the half-load restrictions are in effect. In the event of a transformer failure in this period, it would take the remainder of the half-load season and then the full time required to transport and install the spare transformer, which could be in excess of three months. This significantly exceeds the Ontario best utility practice of 10 days to replace a damaged transformer. This 10-day requirement is built into the Long Time Rating ("LTR") that is assigned to each transformer station in Ontario. Oakville Hydro is committed to following best utility practices, and believes it would not be prudent to subjecting customers to increased levels of service risk.

Based on these restrictions, the opportunity for sharing an emergency back-up transformer with others is not a feasible solution.

Transfer of load away from Glenorchy Municipal Transformer Station in the event of failure

In the event of a substantial power failure at the Glenorchy Transformer Station, only Hydro One's Palermo Transformer Station and Trafalgar Transformer Station would be left to supply power to the North Oakville service area. In July 2011 the load levels in North Oakville reached a peak of 178.7 MW. According to Oakville Hydro's Connection and Cost Recovery Agreement with Hydro One dated October 5, 2010, Oakville Hydro has been allocated a total of 149.7 MW supply in the North Oakville area from Hydro One's Palermo Transformer Station and Trafalgar Transformer Station. Based on the load levels from July 2011 there would be 29 MW of stranded load in North Oakville, and this load level will continue to grow as Oakville develops and takes on new customers. Milton Hydro's customers would be at risk as well.

If there was an outage on only one of the two in-service transformers at Glenorchy Municipal Transformer Station during this peak demand period, Oakville Hydro would be at risk of a second failure that would leave this 29MW of load stranded. It is Oakville Hydro's view that this poses an unacceptable risk to manage.

Conclusion

Oakville Hydro has been prudent and thorough in assessing the alternatives for the acquisition of an emergency back-up transformer for its Glenorchy Municipal Transformer Station and has concluded that the on-site emergency back-up transformer is required in order to minimize risk of disruption to the customers this transformer station currently serves and will serve in the future including. As discussed previously, there are also be two feeders supplying load to Milton Hydro, and one additional feeder which will supply load to the new Oakville Regional Hospital in 2015. Coincident with these new loads, Oakville Hydro requires an emergency back-up transformer that will be sited at Glenorchy Municipal Transformer Station that can be used to replace a damaged transformer within 10 days as per best utility practice. In addition, the emergency back-up transformer would be available to other distributors in these regions, including Hydro One, in the event that they experience a failure.

Therefore, Oakville Hydro has included $5.0 M of capital in its DS Plan in the 2014 Test Year for the on-site emergency back-up transformer.

General Plant

The "Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements" issued on March 28, 2013 by the Board defines the asset category, General Plant, as investments or 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.

Project 14-62 2014 Fleet

Oakville Hydro has the included costs associated with the procurement of eight vehicles in its 2014 Capital Expenditure Plan. Four existing pickup trucks and an existing van are proposed to be replaced with new 2014 vehicles. One existing blocker truck chassis is proposed to be replaced with a large used truck chassis. One existing warehouse forklift is proposed for replacement. The procurement of vehicles that better suit the job requirement will reduce fuel costs, reduce maintenance costs, and reduce overall costs through "right sizing" the vehicle for the job. The replacement of these vehicles will improve response times, improve employee safety and reduce harmful emissions. The vehicles to be replaced and their ages are provided in the following table.

Truck #	Year Make and Type
69	2004 Chevy Crew Cab
75	2005 Chevy Crew Cab
80	2006 Chevy Pickup
65	2003 Chevy Pickup
68	2004 Chevy Malibu
77	2005 Chevy Van
20	1990 International Blocker Truck
406	1991 Forklift

Project 14-64A1 SCADA Enhancements in Loadflow, Contingency Analysis, Fault Detection Isolation Restoration ("FDIR")

The following functional upgrades will be added to the existing SCADA system:

- Loadflow will provide the Control Room Operators with an analysis tool to simulate the impact of system loading levels in order to drive the right solutions.
- Contingency Analysis is a complementary module to Loadflow, and will provide the Control Room Operators with information that highlights critical components in the distribution system, allowing the Operator to reconfigure the system as necessary.
- Fault Detection Isolation Restoration ("FDIR") is also a module that is complementary to Loadflow, and is an element of smart grid transformation that builds a level of automation into the SCADA system. Existing field sensors and controllable switches are leveraged, and the SCADA system is able to take action without Operator intervention to begin system restoral following an outage. A photograph of Oakville Hydro's GIS is provided below.

14-64F Information Technology Infrastructure

The ongoing maintenance of Oakville Hydro's IT infrastructure is core to maintaining the systems the business requires. Asset plans in the IT Strategy define a good basis for a plan that makes sense from a system and cost point of view. The IT strategy is provided as Appendix 6 to the DS Plan. In 2011 and 2012 there was a decrease in the maintenance of the systems due to reorganization in the department. In 2014 there are many systems that require upgrading but only the critical systems are being addressed in the 2014 Capital Expenditure Plan.

16-64D Enterprise Resource Planning ("ERP") & Customer Information System

This project is comprised of a number of upgrades to Oakville Hydro's existing Customer Information System and an upgrade to its Enterprise Resource Planning ("ERP") System, Great Plains – Microsoft Dynamics.

- **Enterprise Resource Planning System ("ERP")**
  Great Plains, Microsoft Dynamics is Oakville Hydro's ERP system and support on the existing GP 2010 will end Oct 2015. Oakville Hydro will implement an upgrade in 2014 in order to ensure that there is no risk of increased costs from vendors to support the system after Microsoft has completed its support. In addition, the upgrade will provide features that will assist in the development of asset management strategies

- **Customer Information System ("Harris")**
  In 2014, Oakville Hydro will automate the collection process to increase efficiency, and reduce bad debt. Oakville Hydro Has received a number of complaints regarding its current process and the automation of the collection process will increase the level of customer satisfaction. In addition, Oakville Hydro will automate service orders and processes to reduce manual processes. This will help reduce billing errors, delayed bills, and improve utilization of resources, which will serve to benefit Oakville customers.

Leasehold HVAC Upgrade

This project is part of a plan to replace HVAC units at Oakville Hydro's corporate office located at 861 Redwood Square in the Town of Oakville. These units were installed in 1994 and have reached the end of their life cycle. Oakville Hydro is experiencing more frequent breakdowns of units requiring replacement, particularly with units that are rooftop and exposed to the elements. Lead time for replacement units on an emergency basis varies from four to ten weeks depending on make and model type/size. Repair costs on these aging units continue to increase. Newer technology and more energy efficient products will result in improved operations, improved reliability and decreased maintenance costs.

List of Appendices

Appendix 1

Asset Management Process

2013/14

Oakville Hydro Electricity Distribution Inc.

Asset Management Process Overview

03/09/2013

Version 1D

Table of Contents

Asset Management Process Overview Purpose and Objective

Oakville Hydro Electricity Distribution Incorporated (OHEDI) produced this Asset Management Process Overview to be a document that provides relevant basic information about the utility, such as area served, customers mix, reliability performance, etc., as well as provide a preamble to the Asset Management Process (AMP) which includes the AM Policy, Strategy, and Objectives and to the Capital Expenditure Plan and Maintenance Expenditure Plan, all of which drive development of investment requirements and ultimately translate into a Business Plan. The AMP will be reviewed and updated on a yearly basis

The purpose of an AMP is to provide a succinct version of what the utility is all about to its shareholders, rate payers, Regulator, employees and general public. The AMP is also used to support Rate Application and to furnish new members of the Senior Management team or Board of Directors with essential background information about the utility.

Corporate Information

As the provider of energy services to the Town of Oakville, Oakville Hydro Corporation (OHC), and its subsidiary OHEDI, envisions itself as being a key facilitator of the growth of the Town of Oakville.

Vision Statement

We energize you

Mission Statement

We provide your best energy and conservation solutions

Corporate Principles

The following set of principles was developed in acknowledgement of a need to augment the ways in which OHC operates, and to reflect the ways in which the Corporation wishes to alter its positioning with its shareholders, customers, suppliers and communities. The foundations for the successful execution of the strategic plan are embodied in the following principles:

- Safety
- Customer focus
- Accountability
- Innovation
- Teamwork
- Communications
- Integrity/Respect

About Oakville Hydro Electricity Distribution Inc.

Utility Overview

OHEDI is Oakville Hydro Corporation's (OHC's) electricity distribution company. Using a network of remotely switched power lines of approximately 1,529 circuit km, 55% of the system underground and 45% overhead, OHEDI has reliably delivered energy to homes and businesses for over a century within the Town of Oakville in the Region of Halton. The service area is approximately 143 square kilometers. OHEDI has gross assets of $227 million and net capital assets of $169 million and a peak demand of 380.1MW. OHEDI offers customer service to developers and consumers, as well as designs, builds and maintains Oakville's power distribution system. OHEDI's customer base includes:

- Almost fifty-eight thousand residential customers;
- Almost five thousand general service customers that require less than 50kW of electrical demand; and
- Almost nine hundred general service customers that require more than 50kW of electrical demand.

Geographical Area Served

Oakville Hydro Electricity Distribution Incorporated (OHEDI) distributes electricity to the Town of Oakville located in the Region of Halton. OHEDI shares borders with Enersource, Burlington Hydro, Milton Hydro, and has its south east border defined by Lake Ontario. The following geographical map provides reference.

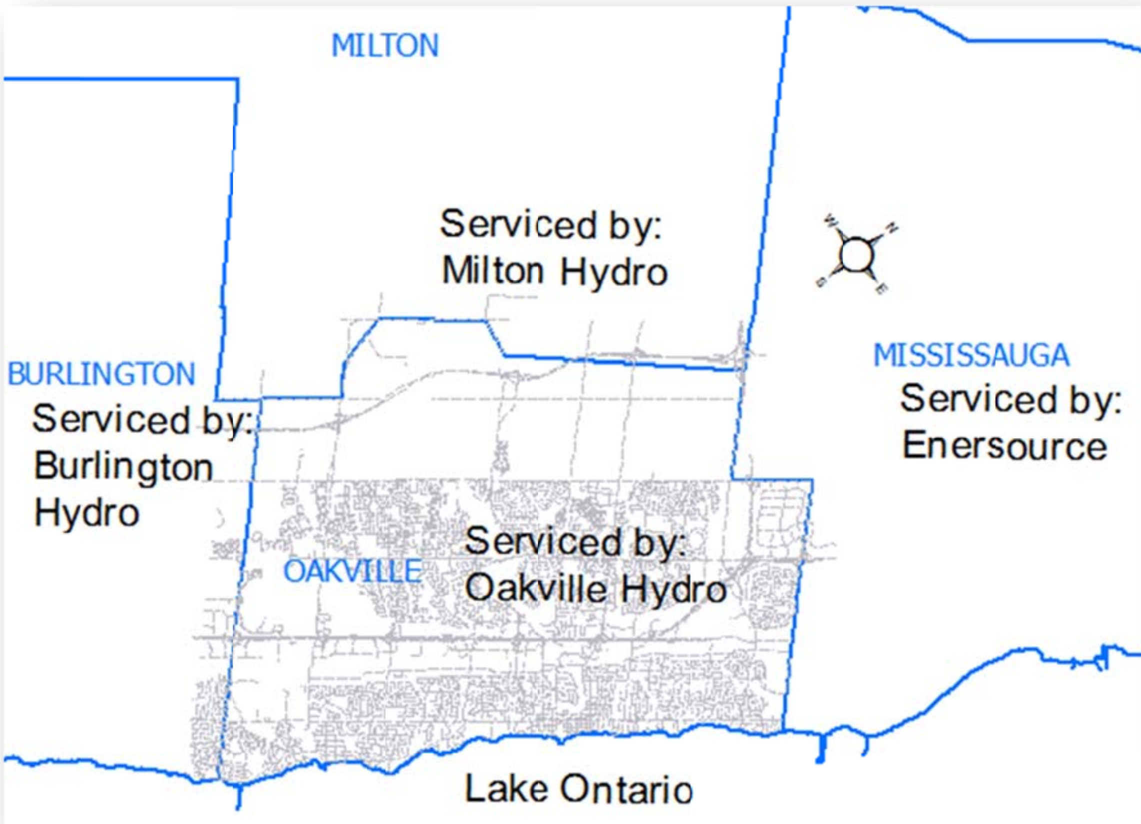


Figure 1

Population Served

OHEDI services 41 sq. km of rural area and 102 sq. km of urban area for a total service area of 143 sq. km. Over the next twenty years OHEDI expects the increase of urban area to encompass most, if not all of the distribution territory.

Climate

Oakville Ontario is considered in the "Dfb" or "Warm Summer Continental" climate of the Köppen climate classification. Extreme minimum temperature recorded at -30°C and extreme maximum temperature recorded at 38°C with average temperatures ranging between -4.9°C and 20.7°C. Seasonal precipitation ranges between 44.2mm to 78.5mm. The Town of Oakville expects an increase of temperature between 2 to 2.6 degrees and an increase of 5.1% precipitation by 2050.

Number of Customers by Segment

OHEDI's customer breakdown as of July 2013 is as follows:

Table 1

Res.	Gen. Serv. <50kW	Unmetered	Gen. Serv. >50kW	Gen. Serv. >1000kW	Gen. Serv. >5MW	Streetlight Accounts	Sentinel Light Accounts	Standard Offer Program Customers	Micro FIT	FIT	Total
58,673	4,941	675	899	16	1	3	25	1	17	3	65,232

Net Book Value of Total Assets

As of December 31, 2012 OHEDI's net book value of assets is $227,537,702 which is comprised of distribution, fleet, building, IT, and Call Centre assets, of which distribution assets account for $153,505,603.

Peak Load and Energy Delivered

The following charts shows OHEDI's peak load and energy delivered, both historical and forecast. OHEDI's peak load was reached in July 2013, of 382MW and the highest energy demand of 1,728,259,011 kWh was in 2004.

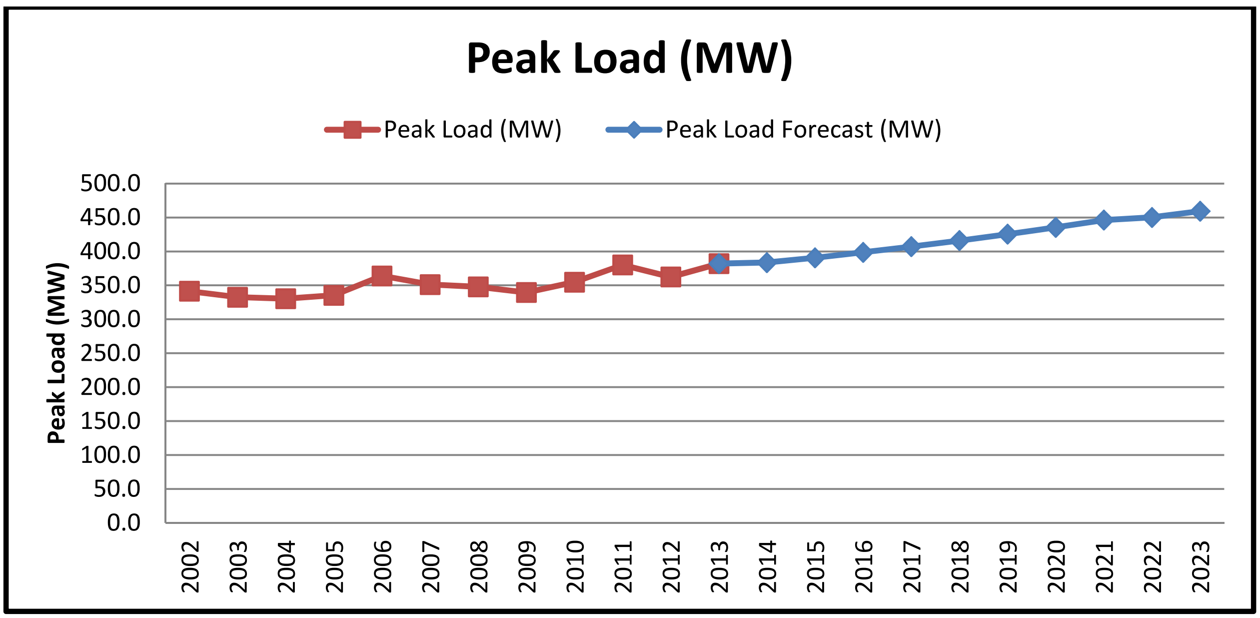


Figure 2

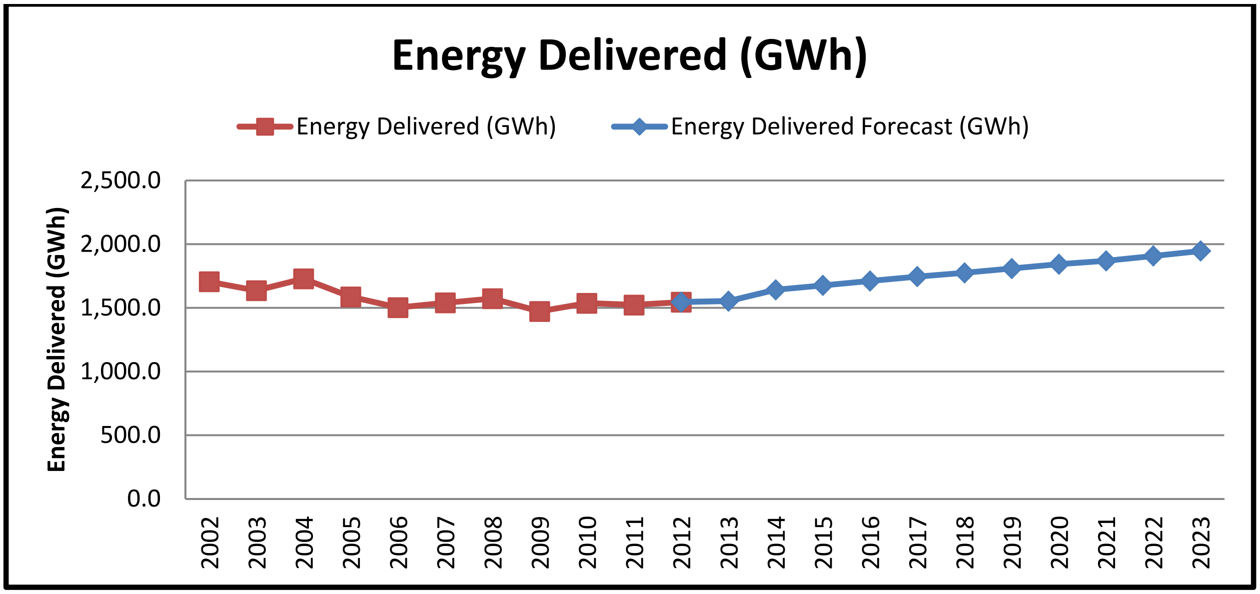


Figure 3

OHEDI's Provincial Ranking

The following table shows OHEDI's overall provincial ranking for number of customers, netbook value of assets, and area served based upon the 2011 Yearbook of Electricity Distributors published on September 13, 2012 by the OEB.

Table 2

	# of Customers	NBV, $M Total Assets	Area served, sq. km
Oakville Hydro	63,614	$218	143
Rank (#1 indicates the most)	Burlington Hydro #12	EnWin Utilities #11	Lakeland Power #33
	Oakville Hydro #13	Oakville Hydro #12	Oakville Hydro #34
	Oshawa PUC #14	Waterloo North #13	Niagara-on-the-Lake #35

Network Configuration & System Description

Supply Points

OHEDI's distribution system is supplied from four Hydro One owned transformer stations (TS), and one municipal transformer station (MTS) as shown in the following table.

Table 3

Name	Owner	Voltage	Area Serviced	Capacity MVA
Bronte TS	Hydro One Networks	115kV to 27.6kV	South West/Central Oakville	(ONAN/ONAF/ONAF) T2 – 50/67/83 (ONAN/ONAF/OFAF) T5 – 56/75/93 T6 – 56/75/93
Palermo TS	Hydro One Networks	230kV to 27.6kV	North West Oakville	(ONAN/ONAF/OFAF) T3 – 50/67/83 T4 – 50/67/83
Oakville TS	Hydro One Networks	230kV to 27.6kV	South East/Central Oakville	(ONAN/ODAN/ODAF) T5 – 75/100/125 T6 – 75/100/125
Trafalgar TS	Hydro One Networks	230kV to 27.6kV	North East Oakville	(ONAN/ODAN/ODAF) T1 – 50/67/83 T2 – 50/67/83
Glenorchy MTS	OHEDI	230kV to 27.6kV	North Central Oakville	(ONAN/ONAF/ONAF) T1 – 75/100/125 T2 – 75/100/125

OHEDI's distribution system is designed to enable the control of load flow in response to changing demand in the Town of Oakville. Hydro One's four transformer stations that supply OHEDI's distribution system are connected to three different transmission circuits. Due to this configuration, OHEDI is called on frequently by Hydro One to shift load in its distribution system to assist Hydro One in managing both the transformer station load levels and the transmission circuit load levels.

System Configuration

Figure 4

27.6kV Circuits

Table 4

Feeder	Transformer Station Supply	OH Wire Lengths (m)	UG Cable Length (m)
13M1	Bronte T.S.	24,224	9,054
13M2	Bronte T.S.	10,085	28,240
13M23	Bronte T.S.	11,035	10,844
13M24	Bronte T.S.	28,548	35,365
13M25	Bronte T.S.	15,388	0
13M26	Bronte T.S.	15,800	0
13M3	Bronte T.S.	22,803	24,391
13M4	Bronte T.S.	14,820	11,828
13M5	Bronte T.S.	13,574	4,533
13M6	Bronte T.S.	4,768	0
13M7	Bronte T.S.	4,484	0
13M8	Bronte T.S.	38,814	20,494
1M14	Glenorchy M.T.S.	15,370	920
1M15	Glenorchy M.T.S.	30,830	82,059
1M16	Glenorchy M.T.S.	8,215	910
1M17	Glenorchy M.T.S.	15,337	24,656
1M18	Glenorchy M.T.S.	30,719	84,493
1M19	Glenorchy M.T.S.	8,525	806
22M43	Oakville T.S.	38,164	84,941
22M44	Oakville T.S.	36,388	14,189
22M49	Oakville T.S.	24,060	1,657
22M50	Oakville T.S.	38,166	15,223
22M51	Oakville T.S.	12,926	16,630
22M52	Oakville T.S.	60,937	36,044
4-M2	Palermo T.S.	14,301	18,366
4-M4	Palermo T.S.	28,388	92,493
4-M7	Palermo T.S.	32,446	185,282
4-M8	Palermo T.S.	46,649	125,047
31M4	Trafalgar T.S.	27,185	32,040
31M5	Trafalgar T.S.	38,123	35,631
31M6	Trafalgar T.S.	38,203	8,126
31M7	Trafalgar T.S.	66,821	94,905
31M8	Trafalgar T.S.	17,054	108,176
Total		**883,214**	**1,208,184**

Information on Oakville T.S. feeder 22M45(Hydro One), Palermo T.S. feeders 4-M1 (Milton), 4-M3 (Milton), 4-M5 (Burlington), and 4-M6 (Burlington) removed from table.

Municipal Substations

OHEDI owns and operates 19 municipal stations, two at 13.8kV and 17 at 4.16kV. The municipal station information is shown in the following table.

Table 5

Name	Voltage	Area Serviced	Capacity (ONAN/ONAF) kVA
Bronte MS 1	27.6kV to 4.16kV	South West Oakville	T1 – 6000/8000 T2 – 6000/8000
Woodhaven MS 2	27.6kV to 4.16kV	South West Oakville	5000/6667
Morden MS 3	27.6kV to 4.16kV	South Central Oakville	6000/8000
Margaret MS 4	27.6kV to 4.16kV	South Central Oakville	6000/8000
Thomas MS 5	27.6kV to 4.16kV	South Central Oakville	6000/7998
Cross MS 6	27.6kV to 4.16kV	South Central Oakville	5000/6666
Industry MS 7	27.6kV to 4.16kV	South East Oakville	6000/8000
Albion MS 8	27.6kV to 4.16kV	South East Oakville	5000/6667
Speers MS 10	27.6kV to 4.16kV	South Central Oakville	6000/8000
Pinegrove MS 12	27.6kV to 4.16kV	South West Oakville	6000/8000
Sunset MS 13	27.6kV to 4.16kV	South West Oakville	6000/8000
Sheridan MS 14	27.6kV to 13.8kV	North East Oakville	T1 – 10000/13330 T2 – 10000/13330
Munns MS 16	27.6kV to 13.8kV	North Central Oakville	T1 – 10000/13300 T2 – 10000/13300
Victoria MS 17	27.6kV to 4.16kV	South Central Oakville	5000/6667
Devon MS 18	27.6kV to 4.16kV	South East Oakville	6000/8960
Marine MS 19	27.6kV to 4.16kV	South West Oakville	6000/7998
Kerr MS 20	27.6kV to 4.16kV	South Central Oakville	6000/8000
Wallace MS 21	27.6kV to 4.16kV	South Central Oakville	6000/8960
Arkendo MS 22	27.6kV to 4.16kV	South East Oakville	6000/8000

13.8kV Circuits

Table 6

Feeder	Municipal Station Supply	OH Circuit Lengths (m)	UG Circuit Length (m)
14F1	Sheridan MS14	17,284	9,178
14F3	Sheridan MS14	3,997	26,054
14F4	Sheridan MS14	8,389	10,397
16F1	Munns MS16	9,955	22,165
16F3	Munns MS16	5,777	15,675
16F4	Munns MS16	11,442	18,381
Total		**56,844**	**101,873**

Information on Sheridan MS14 F2 and Munns MS16 F2 removed from this table.

8.32kV Circuits

There are two areas of OHEDI's distribution system that are fed at 8.32kV, one serviced from Milton Hydro feeders, and the other serviced from OHEDI's 27.6kV system through a set of "Rabbit" step down/up transformers.

4.16kV Circuits

Table 7

Feeder ID	Municipal Station Supply	OH Wire Lengths (m)	UG Cable Length (m)
MS10-F1	Speers MS10	10,476	457
MS10-F2	Speers MS10	12,408	229
MS10-F3	Speers MS10	1,248	13,574
MS10-F4	Speers MS10	4,322	728
MS12-F1	Pinegrove MS12	2,152	892
MS12-F2	Pinegrove MS12	13,132	1,010
MS12-F3	Pinegrove MS12	13,231	1,041
MS12-F4	Pinegrove MS12	2,103	1,044
MS13-F1	Sunset MS13	5,087	3,804
MS13-F2	Sunset MS13	0	6,527
MS13-F3	Sunset MS13	1,847	1,996
MS13-F4	Sunset MS13	8,228	739
MS17-F1	Victoria MS17	3,163	2,831
MS17-F2	Victoria MS17	1,535	7,304
MS17-F3	Victoria MS17	3,581	1,065
MS17-F4	Victoria MS17	2,003	1,867
MS18-F1	Devon MS18	2,719	6,870
MS18-F2	Devon MS18	0	12,429
MS18-F3	Devon MS18	1,277	9,196
MS18-F4	Devon MS18	0	8,425
MS19-F1	Marine MS19	1,700	5,075
MS19-F2	Marine MS19	0	3,865
MS19-F3	Marine MS19	3,828	8,354
MS19-F4	Marine MS19	3,419	2,677
MS1-F1	Bronte MS1	5,686	7,812
MS1-F2	Bronte MS1	7,144	2,154
MS1-F3	Bronte MS1	3,168	8,782
MS1-F4	Bronte MS1	9,890	7,507
MS1-F5	Bronte MS1	2,981	8,335
MS20-F1	Kerr MS20	387	6,991
MS20-F2	Kerr MS20	3,638	2,245
MS20-F3	Kerr MS20	3,369	2,869

Feeder ID	Municipal Station Supply	OH Wire Lengths (m)	UG Cable Length (m)
MS21-F1	Wallace MS21	4,414	652
MS21-F2	Wallace MS21	7,161	973
MS21-F3	Wallace MS21	3,557	1,641
MS21-F4	Wallace MS21	3,893	3,346
MS22-F1	Arkendo MS22	1,430	7,887
MS22-F2	Arkendo MS22	3,451	12,837
MS22-F3	Arkendo MS22	3,259	4,606
MS2-F1	Woodhaven MS2	5,075	2,785
MS2-F2	Woodhaven MS2	4,236	281
MS2-F3	Woodhaven MS2	8,236	1,134
MS2-F4	Woodhaven MS2	5,998	1,393
MS3-F1	Morden MS3	961	4,248
MS3-F2	Morden MS3	4,599	1,609
MS3-F3	Morden MS3	11,933	1,130
MS3-F4	Morden MS3	2,777	5,314
MS4-F1	Margaret MS4	3,525	4,584
MS4-F2	Margaret MS4	6,788	3,719
MS4-F3	Margaret MS4	10,004	6,221
MS4-F4	Margaret MS4	8,326	1,643
MS5-F1	Thomas MS5	8,326	1,948
MS5-F2	Thomas MS5	4,594	1,452
MS5-F3	Thomas MS5	0	6,611
MS5-F4	Thomas MS5	806	6,457
MS6-F2	Cross MS6	5,388	1,377
MS6-F3	Cross MS6	188	4,981
MS6-F4	Cross MS6	6,823	2,933
MS7-F1	Industry MS7	9,577	4,409
MS7-F2	Industry MS7	11,723	1,297
MS7-F3	Industry MS7	18,043	4,419
MS7-F4	Industry MS7	7,329	209
MS8-F1	Albion MS8	6,470	1,781
MS8-F2	Albion MS8	9,197	4,086
MS8-F3	Albion MS8	10,896	605
MS8-F4	Albion MS8	523	1,005
Total		**333,228**	**261,882**

Information on Allan MS11 F1, F2, F3, Arkendo MS22 F4, Cross MS6 F1, and F5 removed from this table.

Major Distribution Assets

OHEDI's major distribution assets and quantities are shown in the following table.

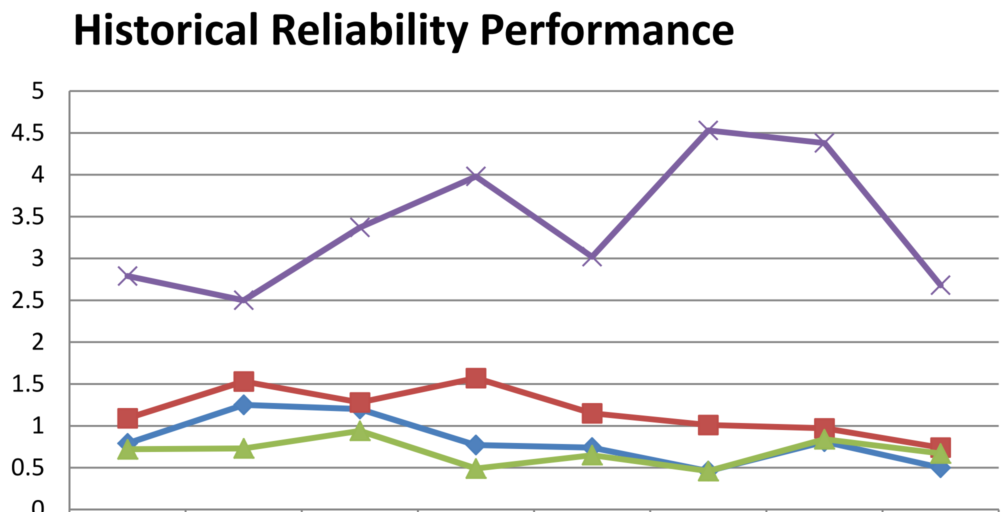
Table 8

Asset	Quantity	Average Age (Yrs.)	Age Range (Yrs.)	Average Condition
MTS Power Transformer (Glenorchy)	2	2	2	Very Good
MS & Customer Specific Power Transformer (CSPT)	36	35.5	1 – 56	Good
Low Voltage Station Switches (4.16 & 13.8kV)	20	3.4	2 – 4	Very Good
Low Voltage Station Breakers (4.16 & 13.8kV)	87	27.2	1 - 44	Good
High Voltage Station Switches (27.6kV Open Air)	38	36.5	1 – 56	Good
High Voltage Station Switches (27.6kV GIS)	46	2	2	Very Good
High Voltage Station Breakers (27.6kV)	21	2	2	Very Good
High Voltage Station Switches (230kV)	2	2	2	Very Good
Overhead Distribution Transformer	1759	26.9	1 – 73	Very Good
Padmount Distribution Transformer	4713	17.8	1 – 50	Very Good
Submersible Distribution Transformer	1243	17.1	1 – 47	Very Good
Vault-style Distribution Transformer	231	39.5	13 – 64	Good
Padmount Switchgear	173	24	1 – 43	Good
Vault-style Switchgear	11	13	6 – 43	Fair
Overhead Gang-Operated Switch	123	29	1 – 32	Good
Overhead Primary Wire Circuit Kilometers	688	29	1 – 72	Good
Underground Primary Cable Circuit Kilometers	840	23	1 – 44	Good
Poles – Mostly wood	8991	26	1 – 72	Good
Secondary Cable Kilometers	1067	23	1 – 72	Fair
Residential Meters	58,720	2.5	1 – 11	Very Good
General Service <50kW Meters	5,014	2	1 – 11	Very Good
General Service >50kW Meters	878	11	1 – 31	Good
General Service >1000kW Meters	16	11	1 – 31	Good
Microfit Meters	24	2.5	1 – 3	Very Good
Primary Meters	44	21	1 – 43	Good
Remote Terminal Units (RTUs)	116	11	1 – 21	Good

*The average age of OHEDI's Distribution System is approximately 25 years old.

The quantities shown are as of August 27, 2013.

Historical Reliability Performance



	2006	2007	2008	2009	2010	2011	2012	2013 (YTD)
SAIDI (hours)	0.79	1.25	1.2	0.77	0.74	0.46	0.81	0.5
SAIFI (outages)	1.09	1.53	1.28	1.57	1.15	1.01	0.97	0.74
CAIDI (hours)	0.72	0.73	0.94	0.49	0.65	0.46	0.84	0.67
MAIFI (outages)	2.79	2.5	3.37	3.98	3.02	4.53	4.38	2.68

Figure 5 – As of July 31, 2013

SAIDI is the average sustained interruption duration per customer served per year (measured in hours). Calculation is "Total Customer Hours of Interruptions" divided by "Total Number of Customers".

SAIFI is the average number of sustained interruptions experienced per customer served per year (measured in outages). Calculation is the "Total Customer Interruptions" divided by "Total Number of Customers".

CAIDI is the average sustained interruption duration experienced by interrupted customers per year (measured in hours). Calculation is SAIDI divided by SAIFI.

MAIFI is the average number of momentary interruptions less than 60 seconds experienced per customer served per year (measured in outages). Calculation is the "Total Momentary Customer Interruptions" divided by the "Total Number of Customers".

The historical reliability performance graph includes issues/events attributable to OHEDI's distribution system and MTS, and does not include external factors such as loss of supply from Hydro One.

Asset Management Process Documents

Asset Management Policy

OHEDI has adopted an Asset Management Policy (AMPo) to help staff support OHC's & OHEDI's vision, goals and objectives. The AMPo contains information such as the asset management policy statements, background and purpose of the policy, the policy principles, guidelines and integration, and key roles & responsibilities for the asset management policy.

Asset Management Strategy

OHEDI has created an Asset Management Strategy (AMS) which was derived from the AMPo, and the OHEDI Strategy. The AMS contains information such as the asset management guiding principles, asset management framework, a 20-Year capital asset view, information regarding major external challenges and commitments, the asset maintenance strategy, and the major distribution assets and replacement criteria.

Asset Management Objectives

OHEDI's Asset Management Objectives (AMO) was derived from the AMS and the OHEDI Objectives. The AMO contains information such as OHEDI's main objectives, asset risk management, performance reporting frameworks, 20-year capital asset view, inspection, condition assessments & health index, asset management system, procurement efficiency and PAS 55.

Capital Expenditure Plan

OHEDI's Capital Expenditure Plan (CEP) was derived from the AMO and the OHEDI Objectives. The CEP contains key information about OHEDI's capital expenditures including, by category, significant projects and activities to be undertaken and their respective key drivers; the relationship between investments in each category, and OHEDI's objectives and targests.

Maintenance Expenditure Plan

OHEDI's Maintenance Expenditure Plan (MEP) was derived from the AMO and the OHEDI Objectives. The MEP contains information such a description of maintenance planning criteria and assumptions and a description of routine and preventative inspection and maintenance policies, practices and programmes.

OEB Chapter 5 Consolidated Distribution System Plan Filing Requirements

Section 5.2 of the Consolidated Distribution System Plan Filing Requirement (CDSPFR) states:
Distributors are encouraged to organize the required information using the section headings indicated. If a distributor's application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application. The following table provides that clarity.

Table 9

CDSPFR Section	OHEDI Document	OHEDI Heading
5.3.1.a ***a description of the distributor's asset management objectives and related corporate goals, and the relationships between them; where applicable, show and explain how the distributor ranks asset management objectives for the purpose of prioritizing investments;***	AMO	OHEDI Capital Investment Objectives And OHEDI Capital Investment Objective Weighting
5.3.1.b ***information regarding the components (inputs/outputs) of the asset management*** ***process used to prepare a capital expenditure plan, identify and briefly explain the*** ***data sets, primary process steps, and information flows used by the distributor to*** ***identify, select, prioritize and/or pace investments; e.g.*** • ***asset register*** • ***asset condition assessment*** • ***asset capacity utilization/constraint assessment*** • ***historical period data on customer interruptions caused by equipment failure*** • ***reliability-based 'worst performing feeder' information and analysis*** • ***reliability risk/consequence of failure analyses.***	AMO	Major Distribution Asset Replacement
5.3.2.a ***a description and explanation of the features of the distribution service area (e.g. urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for asset management purposes, highlighting where applicable expectations for the evolution of these features over the forecast period that have affected elements of the DS Plan;***	This document	About Oakville Hydro Electricity Distribution Inc.
5.3.2.b ***a summary description of the system configuration, including length (km) of underground and overhead systems; number and length of circuits by voltage level; number and capacity of transformer stations;***	This document	Network Configuration and System description
5.3.2.c ***information (in tables and/or figures) by asset type (where available) on the quantity/years in service profile and condition of the distributor's system assets, including the date(s) the data was compiled;***	This document	Major Distribution Assets

CDSPFR Section	OHEDI Document	OHEDI Heading
5.3.2.d ***an assessment of the degree to which the capacity of existing system assets is utilized relative to planning criteria, referencing the distributor's asset related objectives and targets*** • ***where cited as a 'driver' of a material investment(s) included in the capital expenditure plan, provide a level of detail sufficient to understand the influence of this factor on the scope and value of the investment.***	CEP	System Access System Renewal System Service General Plant
5.3.3.a ***description of asset lifecycle optimization policies and practices, including but not necessarily limited to:*** • ***a description of asset replacement and refurbishment policies, including an explanation of how (e.g. processes; tools) system renewal program spending is optimized, prioritized and scheduled to align with budget envelopes; and how the impact of system renewal investments on routine system O&M is assessed;*** • ***a description of maintenance planning criteria and assumptions; and*** • ***a description of routine and preventative inspection and maintenance policies, practices and programmes (can include references to the DSC).***	AMO	Major Distribution Asset Replacement
5.3.3.b ***A description of asset life cycle risk management policies and practices, assessment methods and approaches to mitigation, including but not necessarily limited to the methods used; types of information inputs and outputs; and how conclusions of risk analyses are used to select and prioritize capital expenditures.***	AMO	Major Distribution Asset Replacement

Oakville Hydro Electricity Distribution Inc.
Asset Management Policy

OAKVILLE HYDRO

Policy Number:	AM2012-001	Supersedes Numbers:
Authority to Implement & Manage:	VP-Engineering and Operations & Chief Operating Officer (COO)	
Approval:	CEO	
Approval Date:	03/12/2012	
Effective Date:	03/12/2012	

1 ASSET MANAGEMENT POLICY STATEMENTS

Asset management is a broad strategic framework that encompasses many disciplines and involves the entire organization. The term "asset management", as used in this document, is defined as "the application of sound technical, social and economic principles that considers present and future needs of users, and the service from the asset". To guide Oakville Hydro Electricity Distribution Inc. (OHEDI), the following policy statements have been developed:

a) OHEDI will continuously refine its asset management program to meet system capacity, reliability, security and operating requirements while ensuring long term affordability and responsible stewardship of the distribution system.
b) OHEDI will continue to meet and maintain regulatory and service requirements, employing good utility practices, while balancing between customer expectations and lifecycle costs.
c) OHEDI will maintain compliance to health and safety policies, environmental regulations, and electricity rates and filing requirements.
d) OHEDI will optimize capital and maintenance costs throughout the lifecycle of the asset, and corporate value will be enhanced through timely asset renewal.
e) OHEDI will drive asset investment decisions through condition-based system analysis with a goal to extend asset useful life, as appropriate.
f) OHEDI will incorporate the requirements for system growth and asset replacement or renewal decisions as noted in OHEDI's Smart Grid Strategy and Ontario's Green Energy Act.
g) OHEDI will incorporate the elements of the Asset Management Strategy in long term distribution system planning.
h) OHEDI will continually assess evolving technologies for consideration and potential application.

2 BACKGROUND AND PURPOSE OF POLICY

As the leading provider of energy services to the Town of Oakville, Oakville Hydro Corporation (OHC) envisions itself as being a key facilitator of the growth of the Town of Oakville. This is captured in the corporate vision statement "We energize you". In order to guide staff with the effective implementation of that vision, OHEDI develops policies in key areas of the business that are intended to support OHC's Vision, Goals and Objectives, and provide guidance to staff.

2.1 OHEDI's Vision and Goals for Infrastructure Assets

OHEDI's vision and goal is to develop & manage a safe, reliable, secure, and economically viable distribution system underpinned by well managed and maintained infrastructure assets. These assets include, but are not limited to efficient, economical and reliable electricity distribution networks, safe and reliable support structures, reliable information technology systems, and a productive fleet.

Though these assets age and deteriorate, by using sound asset management practices, OHEDI and OHC can be assured that the assets maintain performance levels, required to deliver the desired service standards in the long term and are managed for present and future users.

The intent of this policy is to articulate OHEDI's commitment to asset management, and provide guidance for implementation. This policy also outlines the manner by which it will be integrated within the organization to be coordinated, cost effective and organizationally sustainable. This policy also demonstrates to the Community that OHEDI is exercising good stewardship, and is delivering affordable services while considering its legacy to future customers.

Staff will implement the policy through the development and use of asset management guidelines and practices. The performance of asset management is organization-specific, reflective of knowledge, technologies, and available tools, and will continue to evolve over time.

3 POLICY PRINCIPLES, GUIDELINES AND INTEGRATION

The key principles of the asset management policy are outlined in the following list.

The organization shall:

- Make informed decisions, identifying all revenues and costs (including operation, maintenance, replacement and decommission) associated with infrastructure asset decisions, including additions and deletions. Trade-offs will be articulated and evaluated, and the basis for the decision recorded
- Integrate corporate, financial, business, technical and budgetary planning for infrastructure assets
- Establish organizational accountability and responsibility for asset inventory, condition, use and performance
- Consult with stakeholders where appropriate
- Define and articulate service, maintenance and replacement levels/outcomes

- Use available resources effectively
- Manage assets to be economically sustainable through condition based maintenance
- Minimize total life cycle costs of assets
- Consider environmental goals
- Consider social and sustainability goals
- Minimize risks to users and risks associated with failure
- Pursue best practices where available
- Establish the capability to report on portions of the asset management program as required

3.1 Guidelines and Practices

This policy shall be implemented by staff using accepted industry guidelines and practices. Staff shall utilize the approved asset management strategy and asset management plans.

The organization will also comply with required capital asset reporting requirements, and integrate the Asset Management program into operational plans throughout the organization.

Strategic asset management plans may be developed for a specific class of assets, or be generic for all assets, and will outline long term goals, processes and steps toward how they will be achieved. The asset management plans will be based on current inventories and condition (acquired or derived), projected performance and remaining service life and consequences of losses (e.g., vulnerability assessments). Operational plans will reflect these details. Replacement portfolios and associated financial plans will consider alternative scenarios and risks, as well as include Executive Management Team consultation.

3.2 Context and Integration of Asset Management within Organization

The context and integration of asset management throughout the organization's lines of business is typically formalized through references and linkages between corporate documents. Where possible and appropriate, OHEDI and its staff will incorporate the essence of this policy in the development of such corporate documents as:

- Smart Grid plan
- Business plans
- Corporate strategic plan
- Corporate financial plan
- Capital Budget plan
- Operational plans and budgets (including fleet and IT)
- Design criteria and specifications
- Infrastructure servicing, management and replacement plans
- Regional system planning

4 KEY ROLES & RESPONSIBILITIES IN SUPPORT OF THE ASSET MANAGEMENT POLICY

OHEDI policies are approved by the Chief Executive Officer (CEO). While staff and other agencies may provide input on the nature and text of the policy, the CEO retains the authority to approve, update, amend or rescind policies.

Role	Responsibility
Identification of issues, and development of policy updates	CEO and staff
Establish levels of service	CEO, staff and public
Exercise stewardship of assets, adopt policy and budgets	VP-Engineering and Operations/COO and staff
Implementation of policy	VP-Engineering and Operations/COO and staff
Development of guidelines and practices	VP-Engineering and Operations/COO and staff
On-going review of policies	CEO and staff

4.1 Implementation, Review and Reporting of Asset Management Work

The implementation, review and reporting back regarding this policy shall be integrated within the organization. Due to the importance of this policy, the organization's asset management program shall be reported annually to the Board, and implementation of this policy reviewed by the CEO.

Actions	Responsibility
Adopt Asset Management Policy	Board and CEO
Monitor and review infrastructure standards and service levels at established intervals	CEO and VP-Engineering and Operations/COO
Develop and maintain infrastructure strategies including development and service plans	Engineering, Asset & Control, and Finance departments
Develop and maintain asset inventories	Asset & Control department
Assess infrastructure condition and service levels	Asset & Control department
Establish and monitor infrastructure replacement levels through the use of full life cycle costing principles	Asset & Control department
Develop and maintain financial plans for the appropriate level of maintenance, rehabilitation, extension and decommission of assets	Engineering, Asset & Control, and Finance departments
Report to Board on status of OHEDI's infrastructure assets and asset management program. The channels include business plans, etc.	CEO, VP-Engineering and Operations/COO

Mike Brown 2012/12/03

Endorsed: Mike Brown, VP-Engineering and Operations/COO Date

2012/12/03

Approved: Rob Lister, President & CEO Date

2013/14

Oakville Hydro Electricity Distribution Inc.

Asset Management Strategy

02/08/2013

Version 1J

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Introduction

The Oakville Hydro Electricity Distribution Inc. (OHEDI) Asset Management Strategy encompasses relevant strategies associated with integrated capital investment, asset maintenance and asset retirement. It covers all distribution assets including power transformers, station switches and breakers, distribution transformers, switchgears, overhead switches, primary wire and cable, secondary wire and cable, poles and meters. It is derived from, and consistent with the goals of OHEDI's strategic plan.

Asset Management Strategy

The following guiding principles define the over-arching strategy for managing assets at OHEDI. Each principle is internally consistent with, and contributes to achieving OHEDI's values:

- Refine continuously the asset management program to meet reliability, demand, security and capacity requirements while ensuring long term affordability and responsible stewardship of the distribution system.
- Continue to meet and maintain regulatory and service requirements employing good utility practices while balancing between customer expectations and lifecycle costs.
- Compliance to health and safety policies, environmental regulations, electricity rates and filing requirements.
- Capital and maintenance costs optimized throughout the lifecycle of the asset, and corporate value enhanced through asset renewal.
- Condition-based system analysis to drive asset investment decisions, with a goal to extend asset useful life, as appropriate.
- System growth and asset replacement or renewal decisions incorporating requirements as identified in OHEDI's Smart Grid Strategy and Ontario's Green Energy Act.
- Longer term distribution system planning incorporating the elements of this asset management strategy.
- Regional system planning with IESO/OPA/Hydro One and neighbouring LDCs factored into this asset management strategy.
- Evolving technologies continually assessed for consideration and potential application.

Asset Management Framework

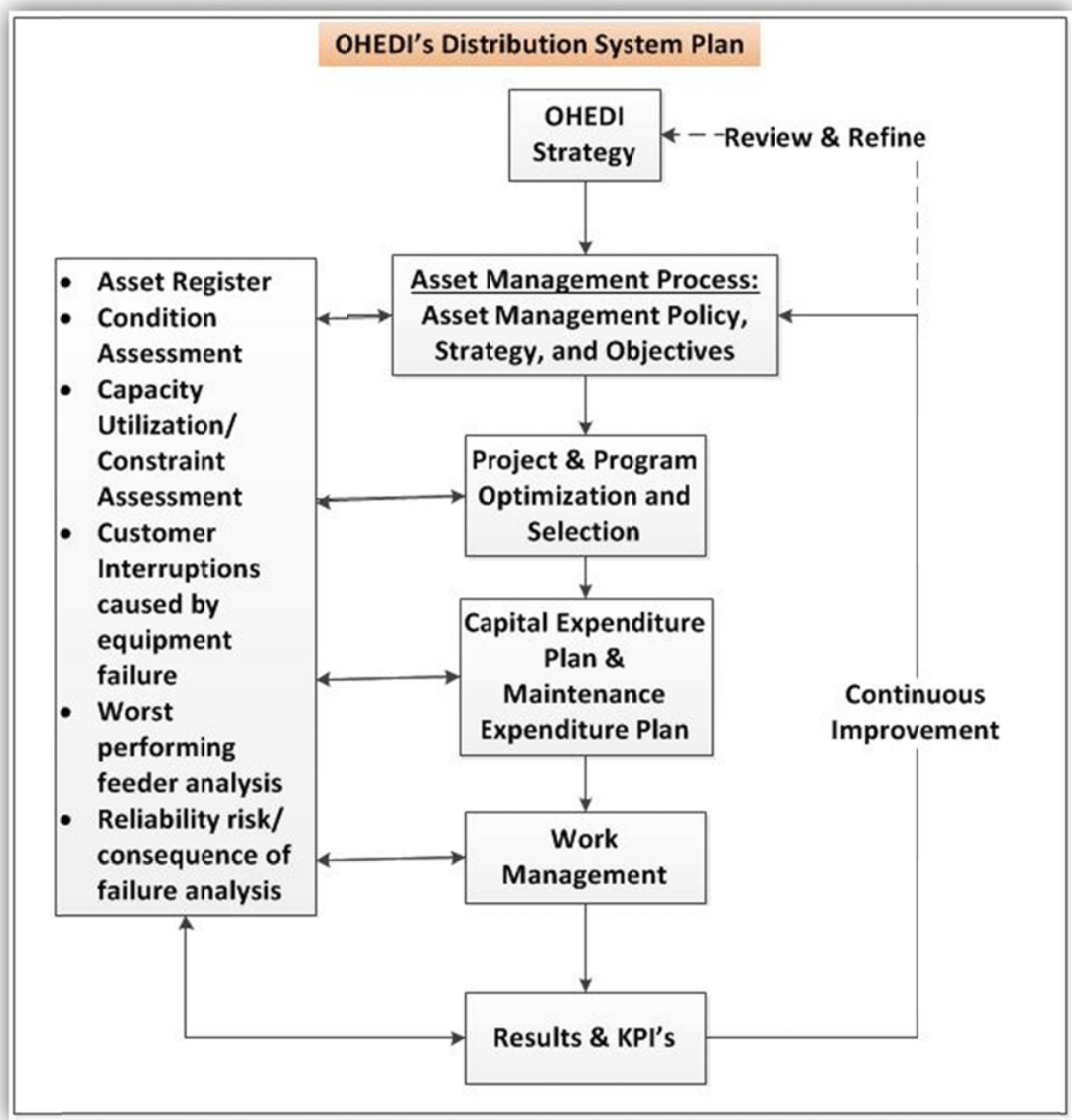


Figure 1

20-Year Capital Asset View

OHEDI has reviewed the Major External Challenges and Commitments, Asset Maintenance Strategy and Major Distribution Asset Replacement topics in order to confirm that all asset replacement activities are done in a long-term sustainable and affordable manner. This approach will prevent 'peaks and valleys' of asset renewal, and allow for a more consistent and relatively steady capital investment over the long-term.

OHEDI has compiled a capital view for the next 20 years using load forecasts, condition/age assessments, and system planning requirements. OHEDI has a number of assets which have passed their typical useful life (TUL). Certain types of assets in our system, based on critical role, implications to service and timelines to replace, have been identified as 'proactive' replacement candidates. These assets will be prioritized for replacement, and are incorporated into OHEDI's multi-year capital plan. There are also assets which are approaching their TUL within this 20 year timeframe as well. OHEDI's intent is to plan replacement of certain assets proactively, based on current condition-based assessments and their role in the system. This approach will assist in mitigating 'spikes' in capital requirements over this period, allowing OHEDI to effectively manage this risk.

Additional assets have been designated as 'run to failure' entities (e.g. distribution transformers) based on localized impacts and ability to efficiently replace. Processes are in-place to manage these cases expediently.

Major External Challenges and Commitments

OHEDI is required to make investments necessitated by external challenges and commitments, which are non-discretionary in nature. These investments include:

- Relocation resulting from municipal/regional/provincial road widening or intersection improvement projects.
- Implementation of Smart Grid initiatives.
- Enhancement of the system to accommodate load growth from new subdivisions or large individual customers.
- Incorporation of distributed generators.

Road widening/intersection improvement projects can be initiated by the Town of Oakville, Halton Region, or the Ministry of Transportation Ontario. These projects are mandatory. OHEDI expects a downward trend in these types of projects over the next 20 years.

OHEDI will actively collaborate in Smart Grid Pilot demonstration projects that have been appropriately funded through the Ministry of Energy and, in addition, approved by the Ontario Energy Board (OEB). Oakville Hydro will ensure that all other smart grid or grid transformation initiatives align with Oakville Hydro's current Strategic Plan by including them in the capital project portfolio to be evaluated (including business case assessment) and prioritized as set out in this Asset Management Strategy.

Customer connection projects can be initiated through the building of a new lot or subdivision, and/or re-building of a currently serviced property. These projects are mandatory as part of our obligation to serve. OHEDI expects an upward trend in these type projects in the next 18 years, at which time it will peak and then decline.

Asset Maintenance Strategy

The OEB outlines the minimum inspection and interval requirement in the Distribution System Code (DSC). The Town of Oakville is considered an urban area therefore the OEB minimum inspection cycle requirements for all transformers, switches, cables, poles, and civil infrastructure is once every three years. The OEB definition of this requirement is as follows:

"Patrol or simple visual inspections consists of walking, driving or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism. In cases where a patrol notices that a problem exists or identifies a condition that warrants a more thorough or rigorous inspection, patrol may then include situations where structures are opened as necessary, and individual pieces of equipment carefully observed and their condition noted and recorded. The specifics of these inspections are recorded, and a summary document prepared in the distributor's annual reports as part of their rates or licensing submissions."

OHEDI utilizes a combination of patrols and maintenance activities to complete these inspection requirements, and records information regarding the condition of distribution assets. A minimum of one-third of each major asset is either patrolled or has maintenance performed each year in order to ensure all assets are inspected a minimum of once every three years. During the patrol, minor maintenance or critical items, that may be immediately addressed, are resolved and reported. Major maintenance that requires more complex coordination is subsequently scheduled for completion within the year, or planned for future years.

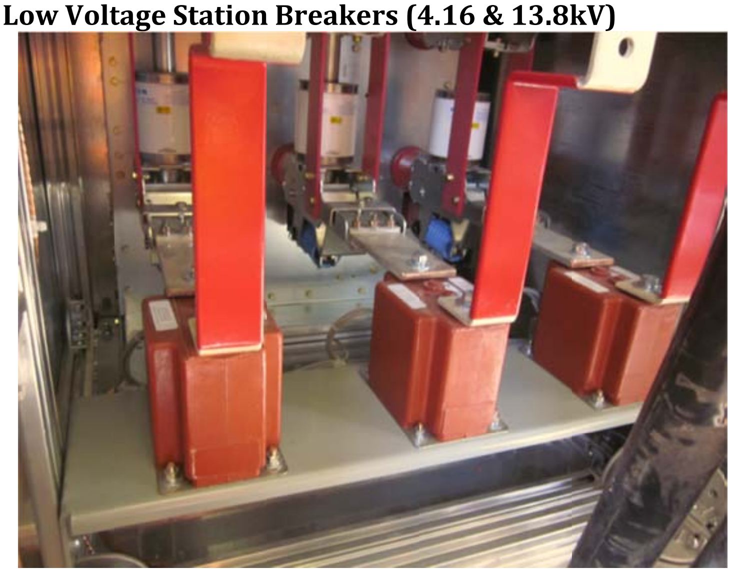
OHEDI analyzes the feedback from inspection and maintenance routines, as part of condition-based asset assessments. Decisions to replace assets versus proceeding with ongoing maintenance (to extend life), are determined based on a business case assessment.

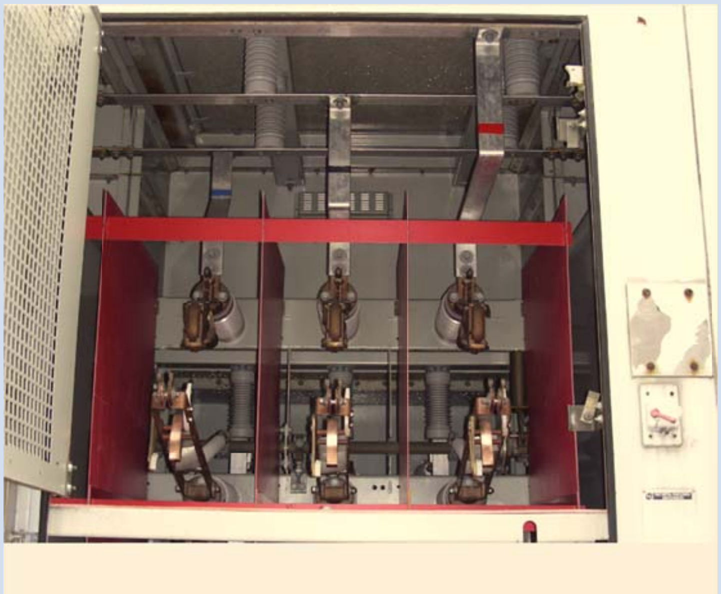
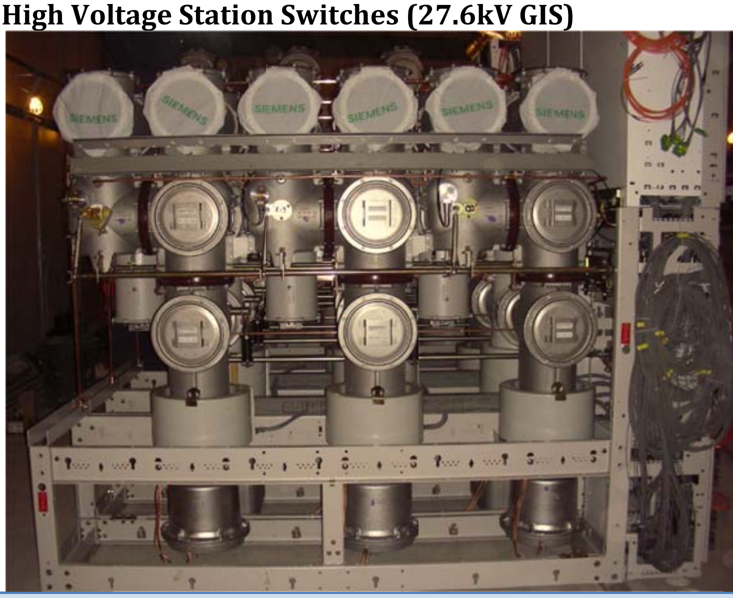
In addition, OHEDI has a Municipal Transformer Station (MTS) – Glenorchy - connected to the grid, which has specific inspection and maintenance standards identified in the OEB Transmission Code.

Major Distribution Assets and Replacement Criteria

Generally speaking, assets labeled with a 'proactive' strategy will be replaced when their age reaches the Typical Useful Life (TUL) and a pre-set condition. Assets labeled with a 'run-to-failure' strategy are allowed to pass their TUL and will only be replaced upon failure. The table below shows how OHEDI treats each major asset class.

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Municipal Transformer Station - Power Transformer (Glenorchy) 	2	1 [1]	Proactive
Municipal Sub-station & Customer Specific Power Transformer (CSPT)  	36	34.5 [1 - 55]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Low Voltage Station Switches (4.16 & 13.8kV) 	20	2.4 [2 - 3]	Proactive
Low Voltage Station Breakers (4.16 & 13.8kV) 	87	26.2 [1 - 43]	Proactive

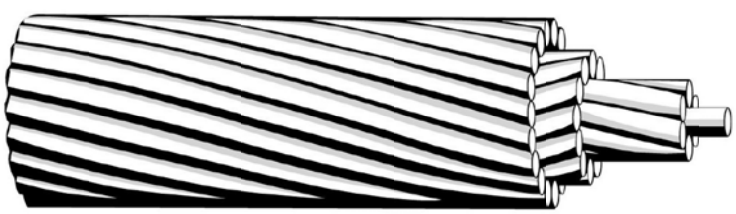
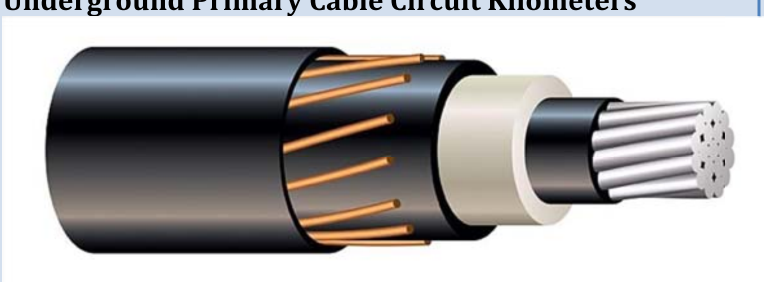
Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
High Voltage Station Switches (27.6kV Open Air) 	38	35.5 [1 - 55]	Proactive
High Voltage Station Switches (27.6kV GIS) 	46	1 [1]	Proactive
High Voltage Station Breakers (27.6kV)	21	1 [1]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
High Voltage Station Switches (230kV) 	2	1 [1]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Overhead Distribution Transformer 	1812	25.9 [1 - 72]	Run-To Failure
Padmount Distribution Transformer 	4857	16.8 [1 - 49]	Run-To Failure

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Submersible Distribution Transformer 	1235	18.1 [1 - 46]	Run-To Failure
Vault-style Distribution Transformer 	223	38.5 [13 - 63]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Padmount Switchgear 	170	23 [1 - 42]	Proactive
Vault-style Switchgear 	11	12 [6 - 42]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Overhead Gang-Operated Switch 	123	28 [1 - 31]	Proactive
Overhead Primary Wire Circuit Kilometers 	561	28 [1 - 71]	Run-To Failure
Underground Primary Cable Circuit Kilometers 	894	22 [1 - 43]	Proactive
Poles – Mostly wood	8004	25 [1 - 71]	Proactive

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Secondary Cable Kilometers 	1067	22 [1 - 71]	Run-To Failure
Residential Meters. 	58,720	1.5 [1 - 10]	Proactive
General Service <50kW Meters	5,014	1 [1 - 10]	Proactive
General Service >50kW Meters	878	10 [1 - 30]	Proactive
General Service >1000kW Meters	16	10 [1 - 30]	Proactive
Microfit Meters	24	1.5 [1 - 2]	Proactive
Primary Meters 	44	20 [1 - 42]	Run-To Failure

Asset	Quantity	Average Age (Yrs.) [Age Range Yrs.]	Strategy
Remote Terminal Units (RTUs) 	116	10 [1 - 20]	Proactive

Summary

This document provides sufficient information, guidance and direction for the development and ongoing management of the Capital Expenditure Plan and Maintenance Expenditure Plan, separate documents which contain the detailed plans to achieve the outcomes of the Asset Management Strategy.

2013/14

Oakville Hydro Electricity Distribution Inc.

Asset Management Objectives

03/09/2013

Version 1I

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Introduction

The Oakville Hydro Electricity Distribution Inc. (OHEDI) Asset Management Objectives encompass relevant objectives associated with integrated capital investment, asset maintenance and asset retirement. It covers all distribution assets including power transformers, station switches and breakers, distribution transformers, switchgears, overhead switches, primary wire and cable, secondary wire and cable, poles and meters. It is derived from, and consistent with the OHEDI objectives.

OHEDI Capital Investment Objectives

The optimization of future programs and project portfolios allows OHEDI to ensure that future expenditures will be applied effectively to the appropriate areas of the system to mitigate risk to OHEDI Objectives described below. The risk is assessed by considering probability and consequence to these Objectives if a project or a program is not completed. The following are OHEDI's Objectives:

Financial

Value

This value deals with ensuring efficient spending of capital and maintenance costs. When assessing the impact on the financial value, OHEDI must consider the mitigation of maintenance expenditures, mitigation of lost revenue due to decreasing reliability, and mitigation of future capital expenditures, through the completion of the proposed projects and programs package, replacement of ageing assets, and maintenance practices.

Risk

Financial risk is measured by lost revenue due to lower reliability, and/or cost avoidance, and its measures are: 1) increased/decreased costs over a 10 year period, and 2) lost revenue or cost avoidance ranging from <$1,000 in lost revenue and/or cost avoidance to >$50,000 in lost revenue and/or cost avoidance.

Goal

The goal is to reduce costs associated with maintaining aging equipment and to mitigate, to the extent possible, future lost revenue due to lower reliability.

Service Quality

Service quality is currently split into two areas of focus. The first is SAIFI which stands for the System Average Interruption Frequency Index. SAIFI is impacted by the number of times a customer experiences a power interruption. The second is SAIDI which stands for the System Average Interruption Duration Index. SAIDI is impacted by the amount of time in which a customer experiences a power interruption.

SAIFI

Value

This value deals with ensuring that frequency of interruption to customers is not increasing. When assessing risk to the SAIFI value, OHEDI considers the impact on SAIFI through completion of the proposed projects and programs-package, replacement of ageing assets, and maintenance practices.

Risk

SAIFI risk is measured by the number of customers that will be without power due to failure of the assets included within the proposed projects and programs package, and its measures are: 1) types of customers affected, ranging from Individual Customer (<50kW) affected to Multiple TS Feeders (>20,000kW) affected, and 2) SAIFI improvements ranging from SAIFI<0.001 Improvement in SAIFI (approximately 60 customer outages) to <0.030 Improvement in SAIFI (approximately 1800 customer outages).

Goal

Goal is to establish a downward trend in OHEDI's SAIFI, and mitigation of potential issues that could cause an increase in SAIFI.

SAIDI

Value

This value deals with ensuring that duration of interruption to customers is not increasing. When assessing risk to the SAIDI value, OHEDI considers the impact on SAIDI through completion of the proposed projects and programs package, replacement of ageing assets, and maintenance practices.

Risk

SAIDI risk is noted by the interruption duration. This risk will come from the amount of time customers could be without power due to the failure of the assets within the proposed project and programs package and its measures are: 1) Interruption duration ranging from Momentary <3 minutes to Outage >12 hours, and 2) SAIDI improvement raging from <0.001 Improvement in SAIDI (approximately 60 customer hours) to <0.030 Improvement in SAIDI (approximately 1800 customer hours).

Goal

Goal is to establish a downward trend in OHEDI's SAIDI, and mitigation of potential issues that could cause an increase in SAIDI.

Socio-Political

Value

This value deals with maintaining and enhancing the brand name and reputation of OHEDI. When assessing impact to the community image value, OHEDI considers the mitigation of written or verbal complaints to the company, through the completion of the proposed projects and programs package, replacement of ageing assets, and maintenance practices.

Risk

Socio-Political risk is measured by the number of written or verbal complaints ranging from <1 written or 5 verbal to >4 written or 20 verbal. The risk is also measured by the complaint escalation level, ranging from Individual concerns made to the company to General public outcry – national media coverage.

Goal

Goal is reduction in existing customer concerns and media focus, and minimizing complaints escalation.

Legal

Value
This value deals with managing cost and number of potential litigations brought against OHEDI by customers and also minimizing legal fees associated with OHEDI's business, e.g. acquiring easement rights.

Risk
Legal risk is measured by litigation costs that could be incurred due to the assets within the proposed projects and programs package. The risk measures are ranging from Litigation costs <$1,000 to Litigation costs >$500,000.

Goal
Goal is reduction in existing litigation costs, and minimizing to the extent possible legal costs associated with OHEDI's business.

Regulatory

Value
This value deals with ensuring compliance with directives/standards/regulations etc. issued by various regulatory bodies, such as OEB, ESA, OSHA, CSA, etc.

Risk
Regulatory risk is measured by severity of possible non-compliance that could occur due to assets within the proposed projects and programs package. The risk measures are ranging from OEB/ESA non-reportable compliance issues to OEB/ESA damaging regulatory impacts – loss of licence/franchise.

Goal
Goal is reduction in existing regulatory compliance issues, and mitigation of potential future regulatory non-compliance situations.

Safety
The safety is currently split into two areas of focus. The first is Employee Safety. The second is Public Safety.

Employee Safety

Value
This value deals with ensuring that OHEDI's employees work in a safe environment and that potential known safety hazards are eliminated or minimized to the extent possible.

Risk
Employee safety risk is measured by assessing potential severity of the safety issue that could occur due to the assets within the projects and programs package ranging from Minor Injury to Multiple loss time incidents and/or fatality.

Goal
Goal is the reduction in existing employee safety issues, and mitigation of employees' exposure to potential safety hazards.

Public Safety

Value
This value deals with public safety hazards associated with OHEDI's assets and is aimed at minimizing to the extent possible public exposure to such hazards.

Risk
Public safety risk is measured by assessing potential consequences of public exposure that could occur due to the assets within the projects and programs package, ranging from Potential for injury with no history, not life threatening to known hazard with history, possibly life threatening.

Goal
Goal is reduction in existing public safety incidents and mitigation of potential future safety hazards.

Environmental

Value
This value deals with managing and mitigating environmental issues to ensure that potential environmental hazards are minimized to the extent possible and that all environmental regulatory requirements are met.

Risk
Environmental risk is measured by the potential severity of environmental issues due to the assets within the proposed projects and programs package, ranging from minor disturbance, documentation not necessary to disturbance requiring Ministry of Environment assistance and public evacuation.

Goal
Goal is reduction in existing environmental incidents and mitigation of potential future incidents.

OHEDI Capital Investment Objective Weighting

In order to provide value added risk disciplined decision making OHEDI has assigned weightings to the above noted Capital Investment Objectives. The weightings ensure that capital investments are prioritized appropriately to mitigate the highest risks. The following figure shows the weighting of each of the objectives.

Figure 1

Safety, OHEDI's highest weighted Strategic Objective, is a combination of both employee safety and public safety sub criteria. Employee safety represents 12.5% and public safety represents 12.5% for a total of 25% weighting. Service quality is a combination of both SAIFI and SAIDI sub criteria. SAIFI represents 8.4% and SAIDI represents 5.6% for a total of 14% weighting.

Asset Risk Management

Risk Management is reviewed regularly by Senior Management with oversight from the Board's Governance and Risk Committee. The executive accountable for facilitating Corporate Risk is the Vice President - Engineering and Operations / COO. In Q3 2010, Oakville Hydro engaged an independent consultant (AESI – Acumen Engineered Solutions International Inc.) to conduct a detailed enterprise-wide risk assessment and assist in the development of a Risk Management framework.

The initial Risk Management review identified, at a high level, the wide range of risk areas to which the complete organization may be exposed. These risk areas were documented on the basis of – risk profile, current state, and control framework. The ten risk areas or categories identified were:

- Safety
- Reliability of Supply
- Customer Expectations
- Workforce Sustainability
- Reputational
- Financial
- Technology
- Cyber Security
- Regulatory and Policy
- Environmental

Each of these corporate Risk Areas, has been assigned to a member of the Executive Management Team for ongoing review and management. Within these areas or categories of risk, there were specific, high priority risks that surfaced as individual priorities or specific risks of greater concern. Based on this outcome, a Risk Management framework was put in-place that defined responsible resource for each specific risk. It focuses in on potential severity and probability as well as process steps to either eliminate, mitigate or manage these specific risks.

Quarterly update meetings are held to discuss each specific risk, in order to have updates provided which include noting any changes to the severity and probability of the risk occurring. It is during these meetings where any contingency arrangements and mitigation techniques are discussed and implemented. The updates are provided to the Executive Management Team (EMT) and then further reported quarterly to both the Board and the Board's Governance and Risk Committee.

Two asset-specific risks were identified in the above-noted process, which were:

- Localized outages due to underground cable faults and;
- Oil Spills from transformers, and oil entering waterways

Other asset specific risks are identified by conducting Subject Matter Expert (SME) interviews in which meetings are conducted with Supervisors and Lead Line Technicians from the company to identify areas of concerns in OHEDI's distribution system.

Specific risks identified were:

- Delta Transformers, which are typically over 40 years old and service Regional waste water treatment pumping stations. These transformers are not easily replaceable, and if they fail could cause flooding in the general vicinity due to the shutdown of the pumping stations they service.
- Poletran Transformers, which are typically over 44 years old and are difficult to operate due to insufficient access. They are also difficult to maintain due to limited availability of parts. Since the transformer are not a standard install, once failed, replacement would not be easy or quick and the customers fed from these locations could experience a lengthy outage.
- Porcelain insulators, which have tended to cause OHEDI issues in the past due to cracking and shattering. There have been a number of documented incidents where porcelain insulators have broken while being used, or have broken on their own, causing issues. These insulators are also more susceptible to contamination causing arcing across them which can turn into a flashover over time.
- Air Insulated 27.6kV Switchgears, which are at risk due to flashovers caused by contamination. The insulators inside of these switchgears are susceptible to salt spray contamination during the winter. When located in a high traffic area the contamination builds up and can cause arcing leading to flashovers. In these cases, typically the switchgear needs to be removed and either refurbished or scrapped entirely depending on the level of damage. Maintenance costs are higher with this type of switchgear due to the level of cleaning required to keep the insulators performing as they should.
- Rear Lot Primary, which is high voltage lines located in the backyards of customers properties. These lines are susceptible to falling tree limbs. Access to repair or replace the equipment in backyards is difficult, and any patrols following an outage are lengthy and cumbersome in order to locate issues.
- Vacuum Switches, which are typically over 30 years old and are prone to sudden failure without warning. There is no maintenance that can be performed in order to prevent these switches from failing, and there are no spare parts in order to have them fixed once failed.
- Submersible Switches, which are typically over 30 years old. There is no maintenance that can be performed in order to prevent these switches from failing, and there are no spare parts in order to have them fixed once failed.
- Livefront Transformers, which are typically over 40 years old. These transformers are not easily replaceable when failed as connections have to be changed from live front construction to dead front construction (terminators to elbows) and most current installations are slab on grade and must be converted to vaults to allow for proper termination of cables. Since the transformers are not a standard install, once failed, replacement would not be easy or quick and the customers fed from these locations could experience a lengthy outage.
- Vault Room Transformers, which are typically over 40 years old. These transformers are located inside buildings, and are typically live front construction. They pose a safety risk to crews performing patrols and maintenance due to their construction style. Typically the

cables servicing these transformers are direct buried, or have three cables installed in a single pipe which would pose a significant issue if the cables were to fail.

- Padmount transformer bushing and elbow replacements in non-vented areas. Older styles of inserts and elbows on padmount transformers do not have venting. The venting helps prevent electrical flashovers from occurring while line forces are isolating these transformers. Without venting present, larger outages are required in order to safely operate the transformers.
- Municipal station ground grid upgrades. The existing ground grids at some of the MS's have mechanical connections instead of compression and some of the metal fixtures within the station grounds are not properly connected to the ground grids.
- Municipal station service upgrades. The existing station services need improvements in order to meet ESA regulations.
- Repeater site upgrades. The current common communication repeater site requires upgrade to latest software/hardware for the OHEDI voice and RTU communication systems.
- Neutral substation protection. The protection schemes on our MS's and TS's and remote switches need to be enabled for neutral overcurrent protection.
- Municipal station fan and fan control upgrades. Existing fans do not have reporting capabilities, nor can be controlled from the OHEDI control room. There is no offsite ability to exercise the fans and to test functionality.
- Intelligent Electronic Device (IED) replacements. The older IED's in the OHEDI system are known to lose their settings requiring them to be reset manually.
- Remote fault indicators. Some areas of OHEDI's distribution system still do not have remote fault indicators. Without these indicators, it takes a longer time to identify the source of outages on the system.

Yearly SME meetings are held in order to capture additional risks that may become prevalent in the distribution system.

Performance Reporting Frameworks

In addition to the enterprise or corporate Risk Management framework and reporting structure notated above, OHEDI has other performance reporting frameworks in-place. This section describes in more detail how OHEDI receives updates regarding the risk position, key performance indicators, and investment requirements.

Financial Risk Reporting

An Internal Auditor conducts a comprehensive financial risk assessment audit using the Committee of Sponsoring Organizations (COSO) model approach. The findings from this audit are reviewed with the Board's Finance and Audit Committee. The Finance department compiles a report each month and forwards it to each department and to the Executives showing the OM&A spending for the previous month, and year-to-date. A detailed capital report is compiled monthly by the Finance department and is forwarded to each department and to the Executives. Both reports are then reviewed to ensure that overspending does not take place in any one area of the business, and appropriate measures can be taken in the case spending is trending too high.

Service Quality Risk Reporting

Monthly Service Quality Indicators (SQI) are published internally and submitted to the OEB annually. In addition, each month, an interruption report is produced which states the current and year-to-date values of System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), and Momentary Average Interruption Frequency Index (MAIFI). The report also includes information regarding significant interruption causes. This report is then used to identify specific areas of investment and maintenance concentration within the OHEDI distribution system.

Community Image Risk Reporting

OHEDI engages an external consultant (UtilityPULSE) to conduct surveys of its customers annually, measuring respondents' feedback from over 20+ attributes that a customer could use to describe their thinking about how satisfied and loyal they might be towards their utility. The categories were split between customer care, company image, and management operations. The primary goal of really listening to customers and responding effectively to them is to create a higher level of affinity with our organization. With higher levels of affinity come higher levels of confidence that employees will handle their problems with speed and professionalism. This process results in less stress on our Customer Call-Centre. It also results in higher levels of acceptance of various communication bulletins and marketing messages which we send to our customers.

By effectively leveraging the findings from the customer survey, OHEDI can have meaningful conversations with staff about customers' – satisfaction, concerns, suggestions, etc. Utilities with a constructive employee culture with high levels of employee engagement will have an easier time navigating the choppy waters of the current environment. The reason is simple, everything OHEDI does and everyone in OHEDI represents the brand – hence its perceived value.

Regulatory Risk Reporting

One of OHEDIs key initiatives is the review of processes relating to compliance with laws and regulations. An inventory of compliance requirements has been compiled and the appropriate executive for each compliance requirement has identified a Departmental resource. The Departmental Resources are responsible for reporting on compliance and for monitoring and communicating any changes in compliance status to Regulatory Affairs for tracking purposes. Compliance status is reviewed on a quarterly basis and presented to the Board's Governance and Risk Committee. Changes to regulatory requirements or compliance status are used to prioritize areas of investment that enable regulatory compliance.

Safety Risk Reporting

An intranet Sharepoint site has been established for OHEDI to track safety issues within the organization. Topics include accident and incident investigation, contractor safety audits, employee injury and illness reports, joint health and safety committee corrective management, safety meeting minutes, management inspection forms, safety hazard notices, and safety tasks.

OHEDI uses another system, called Springboard, where reporting for training accumulation, competency required vs. actual competency, and custom KPIs are tracked.

Ministry of Labour, Canadian Electricity Association, and MEARIE tracking are also completed for benchmarking purposes. The benchmarks are reported to the Board and the Board's Human Resources Committee quarterly, and include loss time injuries, medical aids and hours of training for safety.

Environmental Risk Reporting

Environmental risk reporting is covered under regulatory risk reporting, as it is applicable to Ontario and Canadian regulations. In addition, it is highlighted within the Enterprise Risk framework.

20-Year Capital Asset View

OHEDI has reviewed the Major External Challenges and Commitments, Asset Maintenance Strategy and Major Distribution Asset Replacement topics in order to confirm that all asset replacement activities are done in a long-term sustainable and affordable manner. This approach will prevent 'peaks and valleys' of asset renewal, and allow for a more consistent and relatively steady capital investment over the long-term.

OHEDI has compiled a capital view for the next 20 years using load forecasts, condition/age assessments, and system planning requirements. OHEDI has a number of assets which have passed their typical useful life (TUL). Certain types of assets in our system, based on critical role, implications to service and timelines to replace, have been identified as 'proactive' replacement candidates. These assets will be prioritized for replacement, and are incorporated into OHEDI's multi-year capital plan. There are also assets which will reach their TUL within this 20 year timeframe. OHEDI's intent is to plan replacement of some assets proactively based on current condition-based assessments and the criticality of their role in the system. This approach will help level the capital requirements over this period, and effectively mitigate the risk of critical asset failure.

Additional assets have been designated as 'run to failure' entities (e.g. distribution transformers) based on localized impacts and ability to replace in a timely manner in the event of failure. Processes are in-place to manage these cases expediently.

Major External Challenges and Commitments

OHEDI is required to make investments necessitated by external challenges and commitments, which are non-discretionary in nature. These investments include:

- Relocation of assets resulting from municipal/regional/provincial road widening or intersection improvement projects.
- Enhancement of the system to accommodate load growth from new subdivisions or large individual customers.
- Installation of new residential, commercial and condo meters.
- Incorporation of distributed generators.
- Meeting minimum OEB inspection and testing requirements

Road Widening/Intersection Improvements

Road widening/intersection improvement projects can be initiated by the Town of Oakville, Halton Region, or the Ministry of Transportation Ontario. These are mandatory projects. Over the last several years MTO, Region & the Town increased their spending on infrastructure in part due to government incentives for infrastructure spending. This is tailing off now, although there are talks of more infrastructure spending incentives. In Oakville, the QEW widening and HOV lane projects are complete with no anticipated further projects in the foreseeable future. For the Region, Bronte Road/Highway 25 has been completed, Ninth Line up to Dundas Street will be completed in 2013, Neyagawa Boulevard will be completed in 2013 and Dundas Street widening will be completed in the 2013-2014 period. Trafalgar Road and Ninth Line, north of Dundas Street, have not had impact assessments completed at this time. A lot of the major Town widening have been completed to-date. Two grade separations may have an impact, one being on Kerr St. and the other on Burloak Drive. The original lines were designed with this in mind so minimal impact is anticipated. The circuits constructed in north Oakville for Glenorchy MTS were positioned to have minimal impact if road widening occurs, with the best planning information available at the time. For these noted reasons, OHEDI expects a downward trend in these types of projects over the next 20 years.

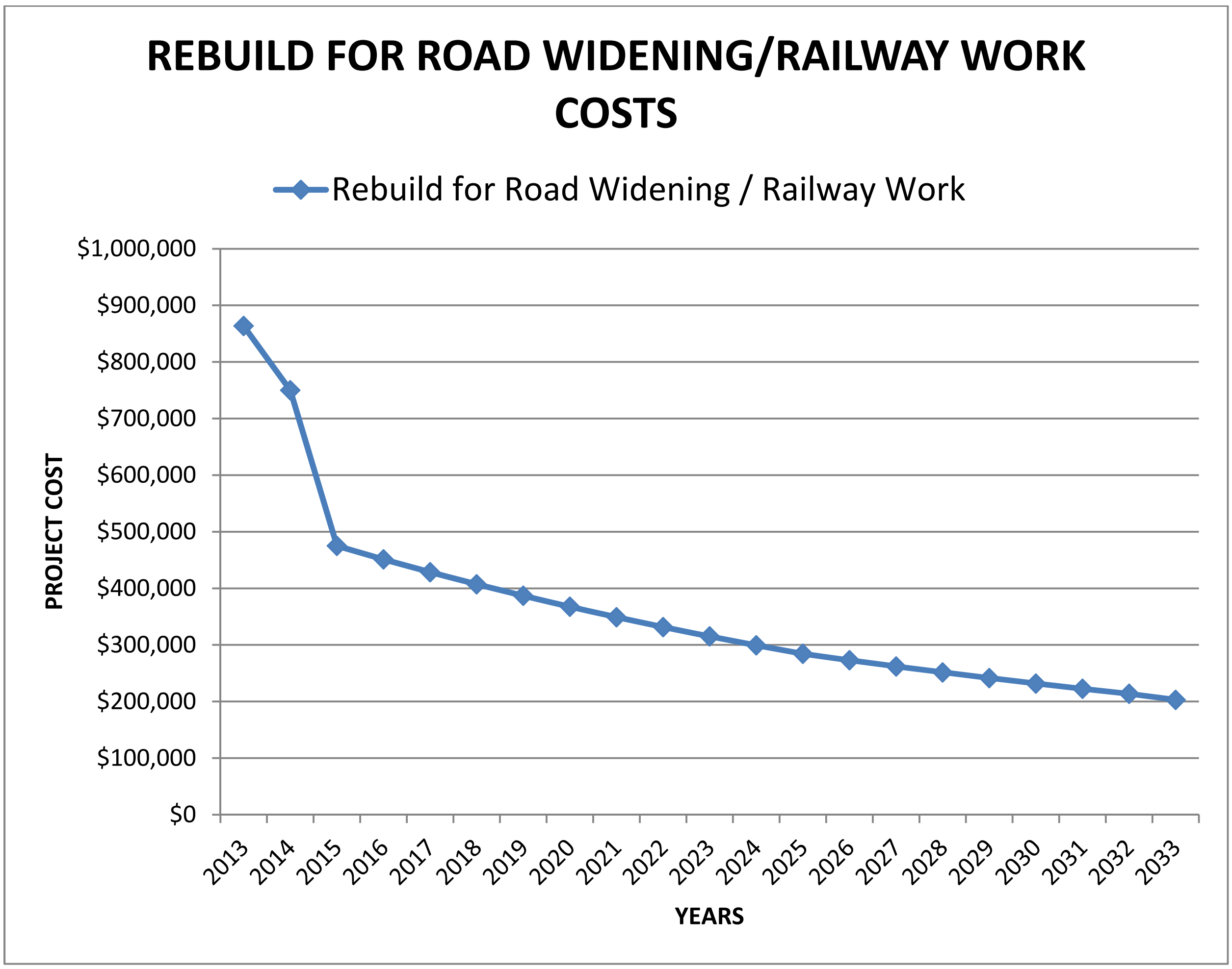


Figure 2

SMART Grid

OHEDI will actively collaborate in Smart Grid Pilot demonstration projects that have been appropriately funded through the Ministry of Energy and, in addition, approved by the Ontario Energy Board (OEB). OHEDI will ensure that all other smart grid or grid transformation initiatives align with Oakville Hydro's current Strategic Plan by including them in the capital project portfolio to be evaluated (including business case assessment) and prioritized as set out in these Asset Management Objectives.

Customer Enhancement

Customer connection projects are initiated through the building of a new lot or subdivision, and/or re-building of a currently serviced property. These projects are mandatory as part of our obligation to serve. OHEDI expects an upward trend in these type projects in the next nine years, at which time it will have some stability.

In the 27.6kV Additions category, OHEDI required additional funding in 2013 to allow for the building of two required projects. The first project was the addition of two feeders from the Glenorchy MTS to supply Milton Hydro. The second project was a feeder addition to supply the new Oakville Hospital.

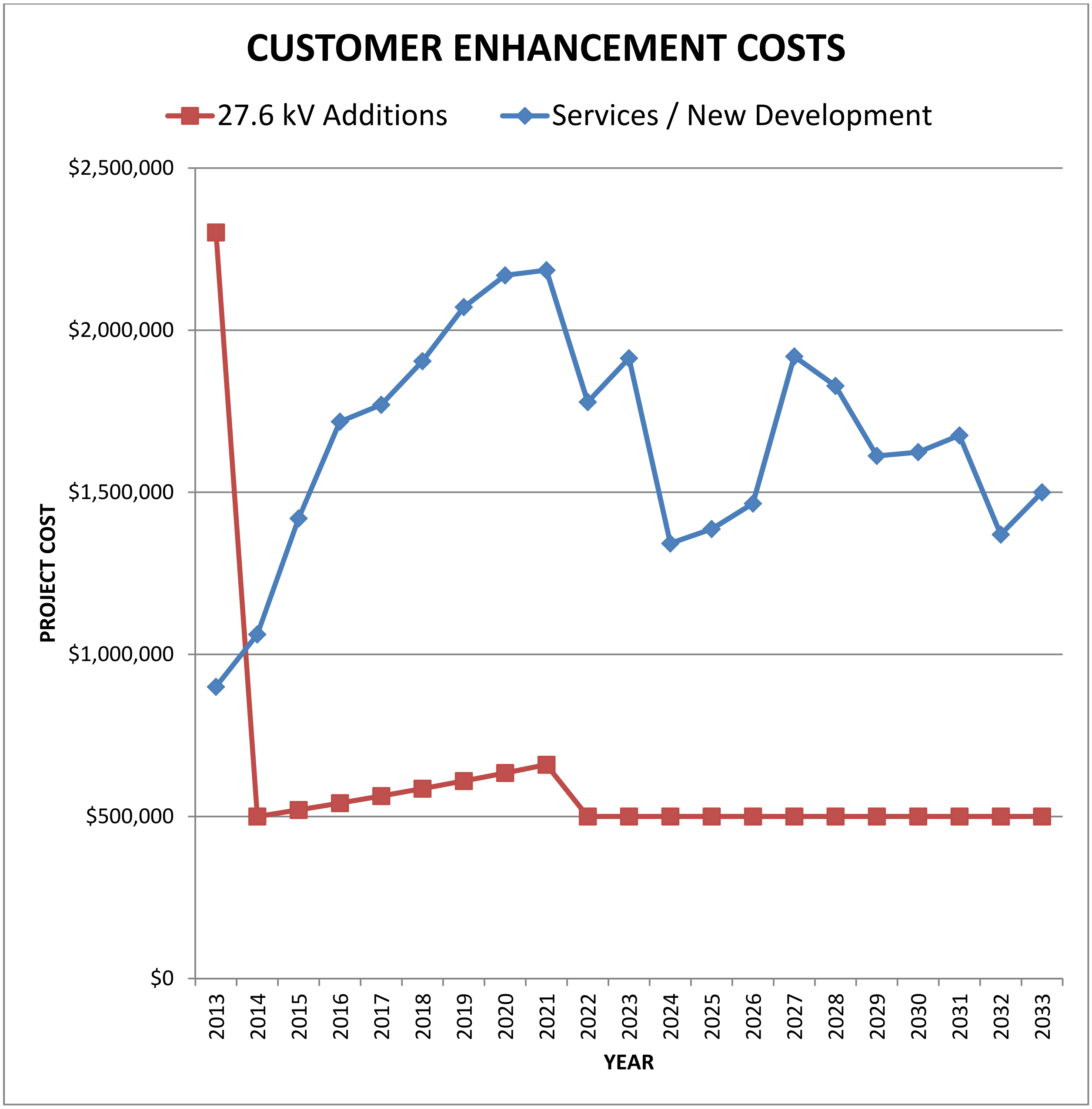


Figure 3

Installation of new meters has three major components. Residential meter installation requirements typically follow the costs for services/new development, as shown in the previous figure. Commercial meters have been known to flat line trend and should only represent a pillowing factor to the overall budget. Residential condo meters are unpredictable past approximately two years, however OHEDI does not expect a significant increase in these meters over the next 20 years.

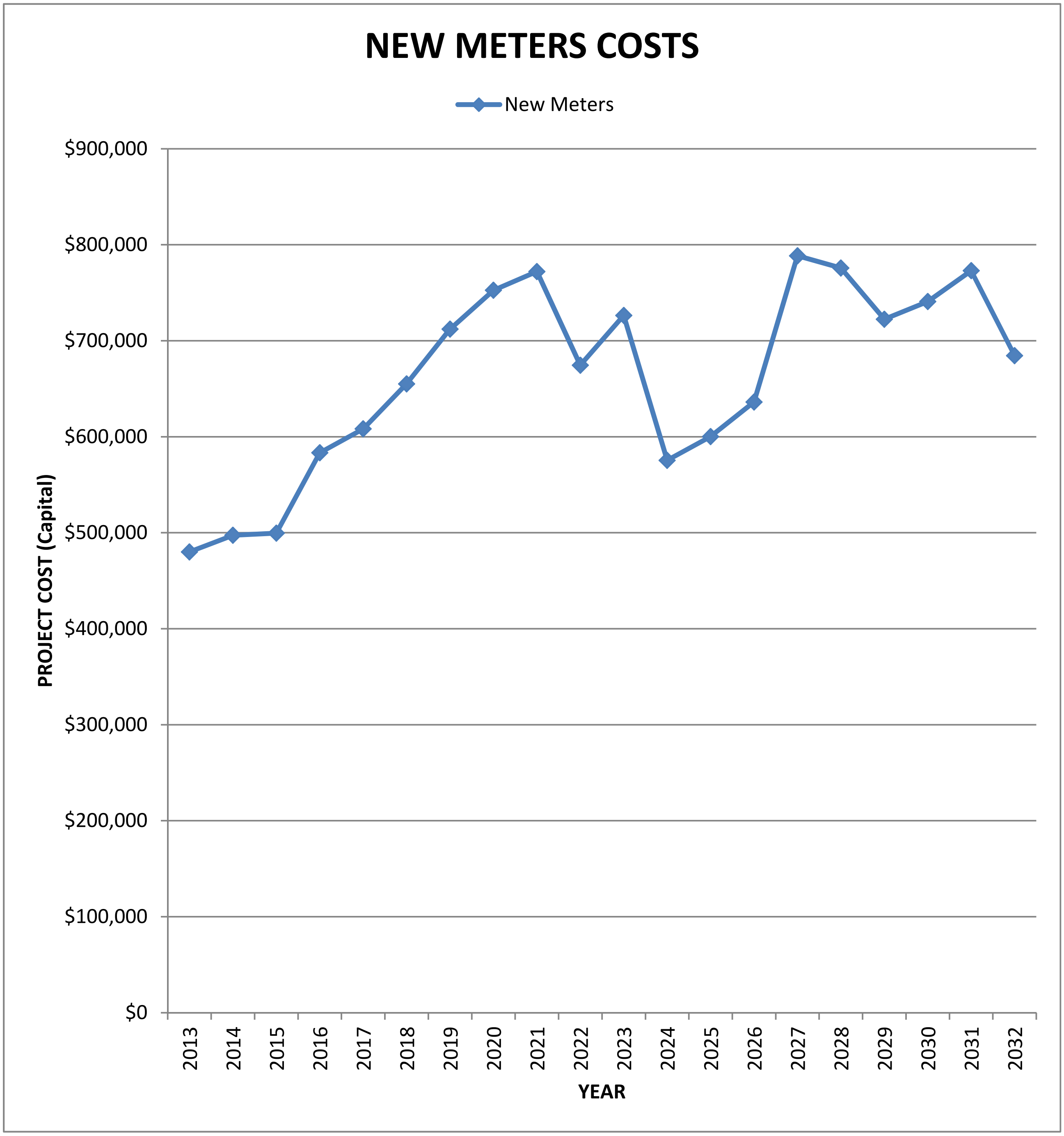


Figure 4

Inspection and Testing Requirements Distribution Assets

Inspection and testing requirements are internally scheduled, and involve the maintenance and patrols of the distribution infrastructure. The patrols and associated maintenance to address defects, are mandated by regulatory standards. OHEDI expects an upwards trend in inspection and testing requirements over the next 20 years.

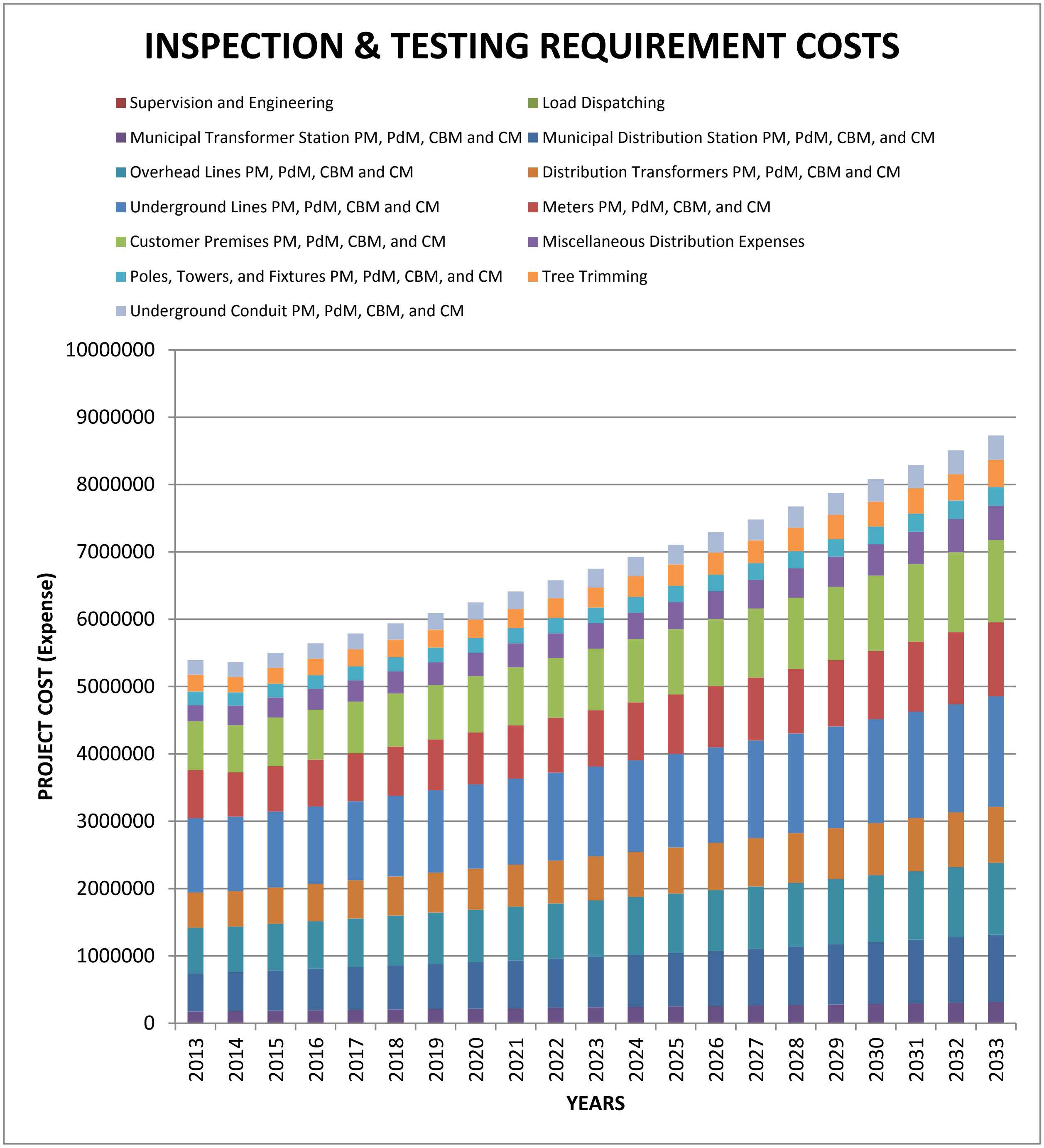


Figure 5

Major Distribution Asset Replacement

A number of inputs are used in order to select major distribution assets for replacement.

Asset Register

Major distribution asset records currently reside in various locations. Power and distribution transformer records are kept in OHEDI's Microsoft Dynamics GP program, low voltage breakers and high voltage switch records are mainly kept in paper format with some information stored in Microsoft Excel files, switchgear and switch records are kept in a Microsoft Access database, overhead wire and underground cable records are kept in paper format with some information stored in the ESRI Geographic Information System (GIS), pole records are kept in a Microsoft Access database, meter records are kept in the North Star Harris Customer Information System, and primary meter records are kept in a Microsoft Excel file.

Most records contain asset:

- Tracking numbers
- Descriptions
- Quantities
- Manufacturers
- Serial numbers
- Warranty information (where applicable)
- Acquisition dates
- Service dates
- Physical locations
- Disposal dates

OHEDI is striving to also include the acquisition cost of the asset, the assets salvage value, the asset's useful life, the depreciation method, and the current book value with the individual asset registers as sometimes this information is kept in other locations, or not kept at all.

OHEDI is in the process of establishing a single centralized location (Maximo System) for the Asset Register for all major distribution assets which will include all the above record attributes. See the "Asset Management Systems" section of this document for details.

Condition Assessments & Recommendations

Asset condition is assessed & documented noting any urgent issues. In some cases simple maintenance tasks cannot mitigate these issues, prompting the need for a capital replacement project. In these situations a project is initiated, designed, planned & estimated to remedy the outstanding issues. It is preferable to group like assets together for replacement in these situations to reduce the number of project packages.

Conditions of assets are kept in various locations like described in the equipment register information above, and each major distribution asset has various conditions noted in order to determine follow-up maintenance or capital expenditure.

OHEDI is striving to have a single centralized location for the Condition Assessments for all major distribution assets which will include all noted condition attributes. See the "Asset Management Systems" section of this document for details.

Asset Capacity Utilization/Constraint Assessment

OHEDI annually reviews capacity utilization at the transformer station connection points (at 27.6kV) and at the 27.6 kV feeder level, on an individual feeder basis. The review is normally done at the time of the annual system peak, to most accurately determine the system capacity utilization. The SCADA (System Control and Data Acquisition System) is used to monitor feeder loads and assists in the capacity utilization review. For newly added loads, capacity utilization and constraint assessment is done on a project by project basis. For new developments in North Oakville, at present, the assessment is very straightforward due to the recent addition of the OHEDI owned Glenorchy MTS transformer station and associated new 27.6kV feeders. At present there is substantial available capacity for new loads in this area. For new load additions in other established areas, capacity utilization and constraint assessment is done on a project by project basis to determine if upgrades or load transfers to other feeders are necessary.

Reliability-Based 'Worst Performing Feeder" Information and Analysis

Worst Performing Feeder analysis is performed on a yearly basis. Each feeder is reviewed for their SAIDI, CAIDI, and SAIFI metrics. The Control Room Supervisor compiles the report from information that is available in the current outage reporting system. This analysis helps identify possible areas for capital expenditure.

Reliability Risk/Consequence of Failure Analyses

Currently these analyses are being completed for individual projects selected for replacement. Each project is reviewed by its impact to the OHEDI Capital Investment Objectives, and prioritized as such. OHEDI is looking to assign risk to all major distribution assets in order to identify the risk level and consequence of failure of the entire system.

Interviews

Annual interviews are conducted with internal Subject Matter Experts (SMEs) and risk management primes at OHEDI in order to identify future project requirements. Condition assessments do not necessarily cover the full extent of projects that should be considered. These interviews will capture a wider range of projects, including those that are safety and operations related.

Optimization of Project Portfolios

The Optimizer software was obtained from UMS through Abicus Management Solutions Inc. in 2009. This software package enables the evaluation of a multi-year project portfolio, and optimizes the project selection based on a set of weighted criteria.

The optimization of future project portfolios allows OHEDI to ensure that future capital costs will be applied to the appropriate areas of the system to mitigate risk and improve value. Future projects are evaluated by considering both their risk and probability if not completed, and their value if completed. Projects are evaluated based upon the risk and value associated with the capital investment objectives and weightings.

The optimization of these project portfolios will produce a prioritized list of projects to be completed in future years. The optimizer will prioritize this list of projects based upon the individual effects each has on the capital investment objectives and weighting. When applying the projected annual capital budget amount to the optimization, a list of projects to be executed by year will be produced. This list can be modified by either increasing or decreasing the capital budget amounts if required.

Typical Useful Lives(TUL)

The figures in the following sections illustrate the differences between a proactive capital replacement program, and a replacement program based upon TUL. Obviously, OHEDI does not expect every asset to fail at the exact TUL date; these metrics are used as a baseline to illustrate the feasibility of a proactive replacement program for distribution assets to mitigate peaks and valleys in capital expenditure over a 20 year timeframe. To establish the TUL expectations, OHEDI has considered current asset age data and the Kinectrics Inc. Report titled “Asset Depreciation Study for the Ontario Energy Board” number K-418033-RA-001-R000 dated July 8, 2010.

The following cost estimates were created using a 2% inflation increase per year over a 20 year timeframe in order to accurately reflect capital costs over time.

Municipal Substation and Customer Specific Power Transformers

Asset Evaluation

Power Transformers form a relatively small asset base. Year of manufacture ranges from 1957 to 2011 with the average age being 35 years old. OHEDI uses a TUL of 45 years. Based upon this timeframe, currently 5 transformers have exceeded the TUL of 45 years.

The following bar graph shows the number of Power Transformers by year that will exceed this TUL within the next 20 years.

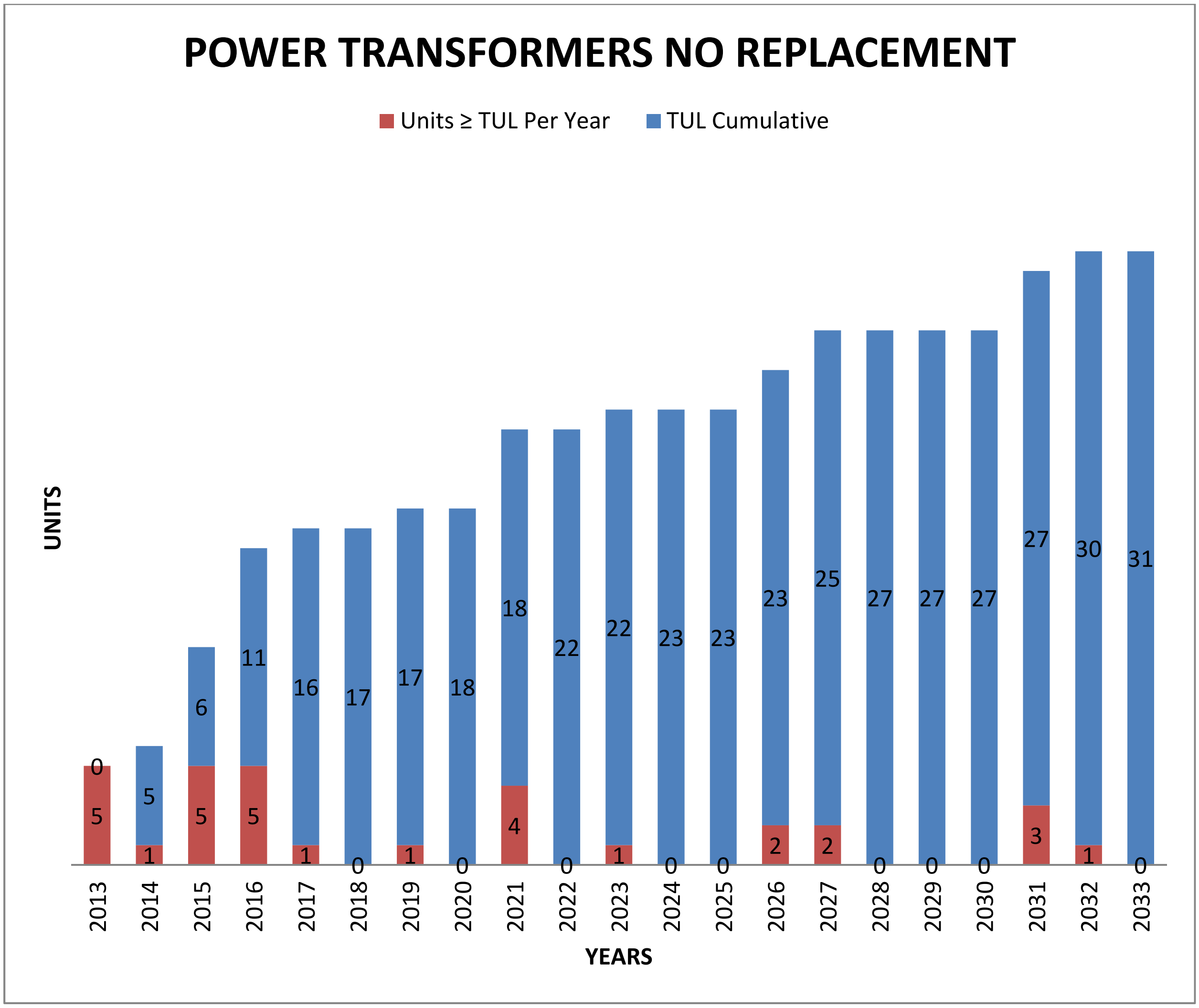


Figure 6

Investment Optimization

For Customer Specific Power Transformers the customers load will be reviewed to determine if it can be serviced from a standard three phase padmount transformer. Utilizing a standard three phase padmount transformer will reduce both material and installation cost, and decreases spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace one power transformer per year for the next 10 years and two power transformers for the following 10 years.

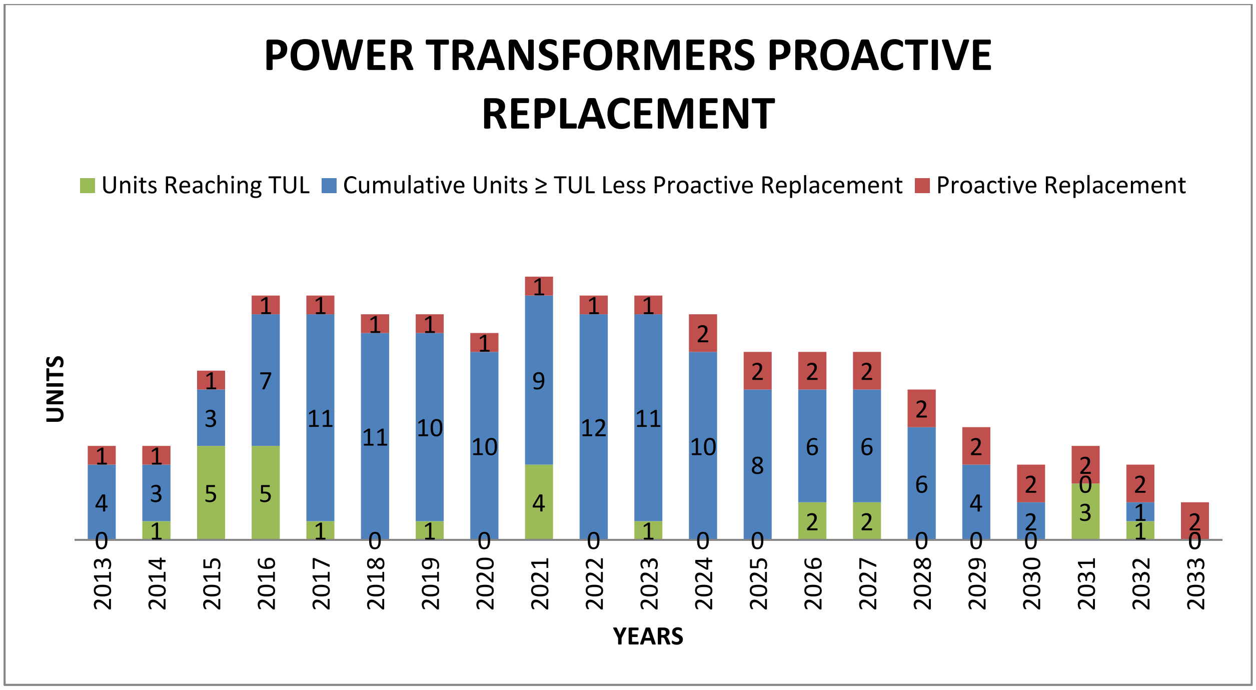


Figure 7

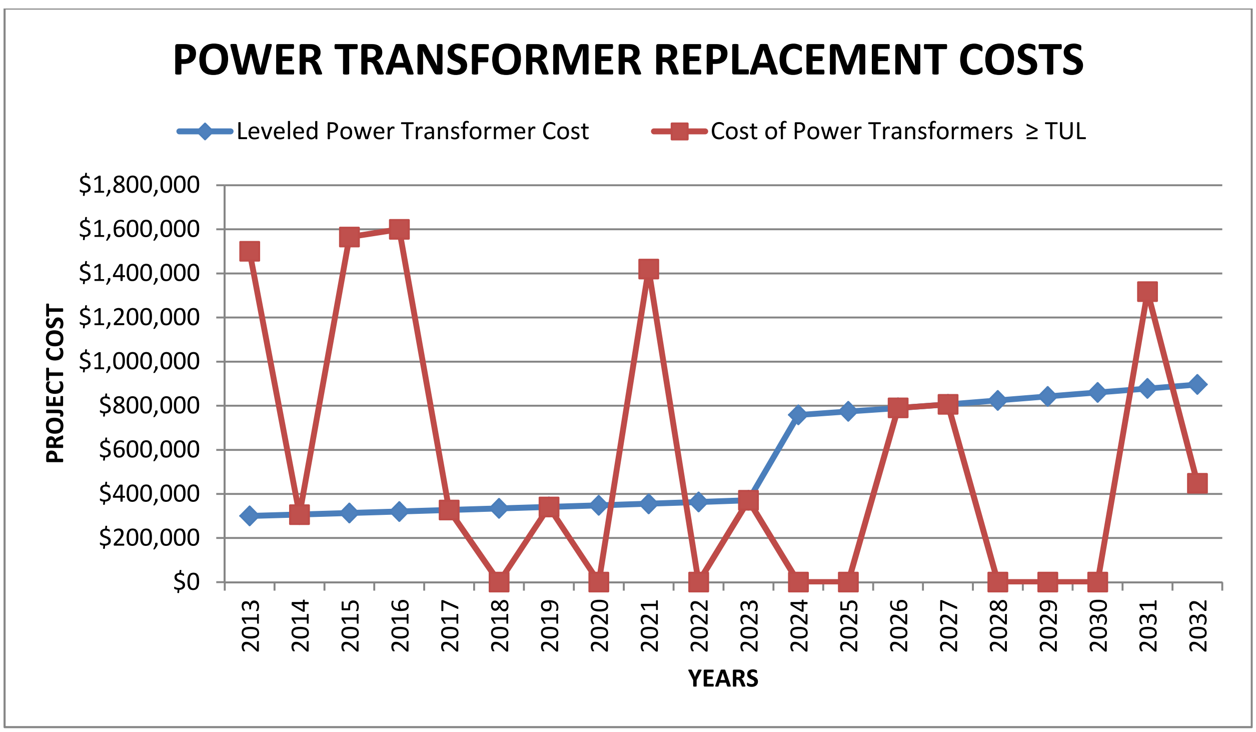


Figure 8

Low Voltage Station Switches and Breaker Line-ups

Asset Evaluation

Low voltage station switches and breaker line-ups form a small asset base. Year of manufacture ranges from 1969 to 2010 with the average age being 25 years old. OHEDI uses a Typical Useful Life (TUL) of 25 years. Based upon this timeframe, currently 11 low voltage switches and breaker line-ups have exceeded this TUL of 25 years.

The following bar graph shows the quantity of low voltage station switches and breaker line-ups that will exceed this TUL within the next 20 years.

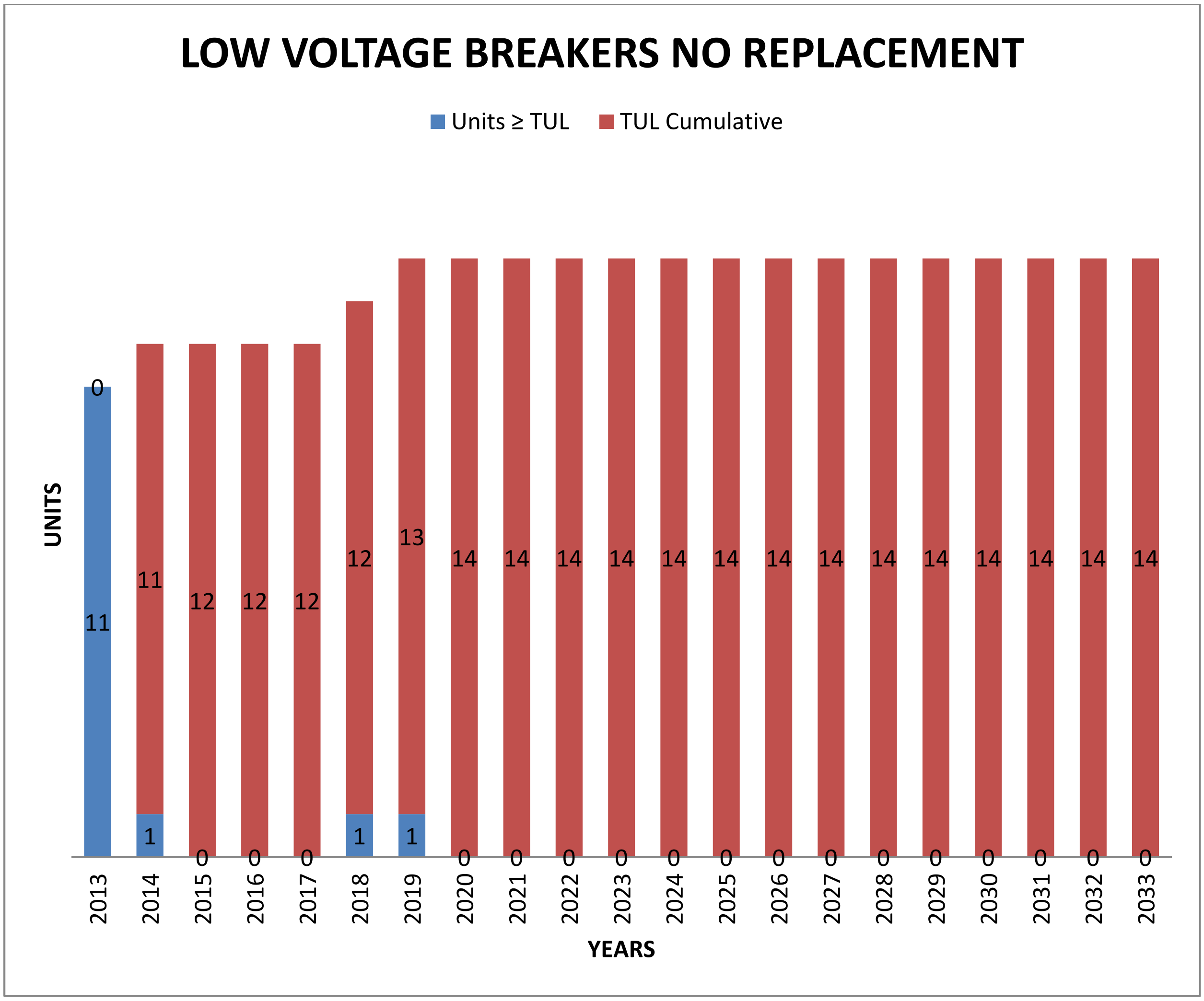


Figure 9

Investment Optimization

Utilizing standard padmount switchgear will reduce both material and installation cost, and allows for spare inventory in the case of equipment failure. Future investigations into this will take place to determine the feasibility of this option.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace one low voltage switch and breaker line-up per year for the next 13 years.

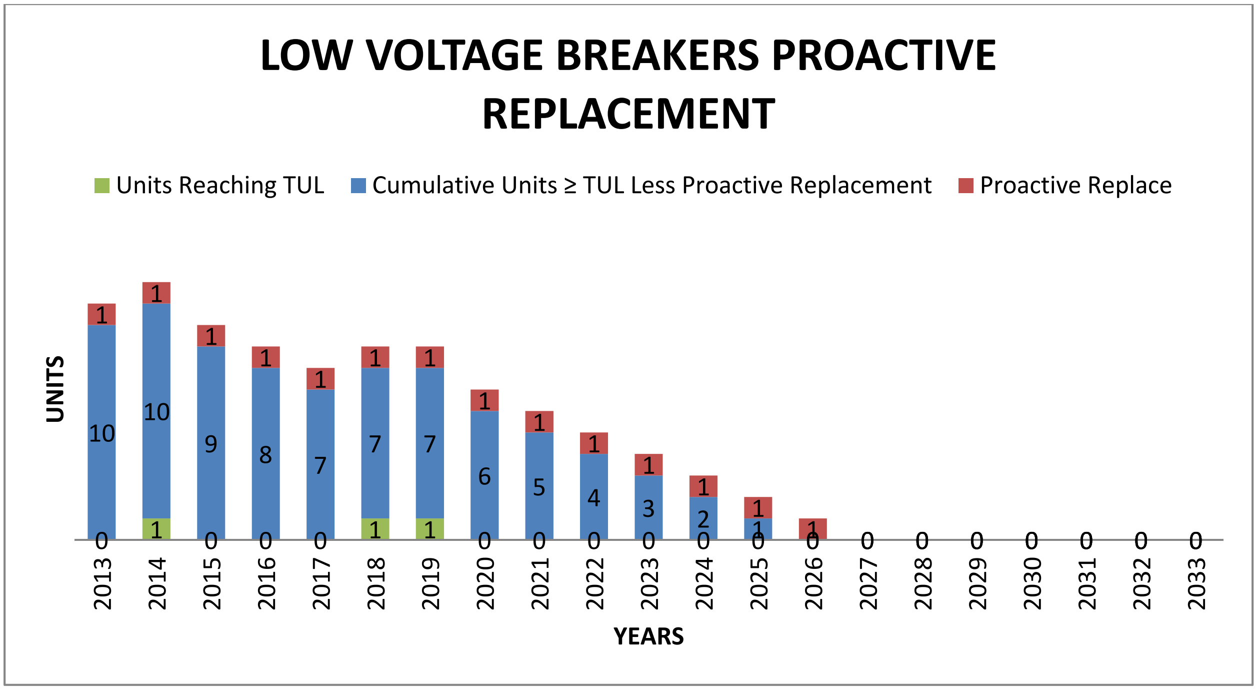


Figure 10

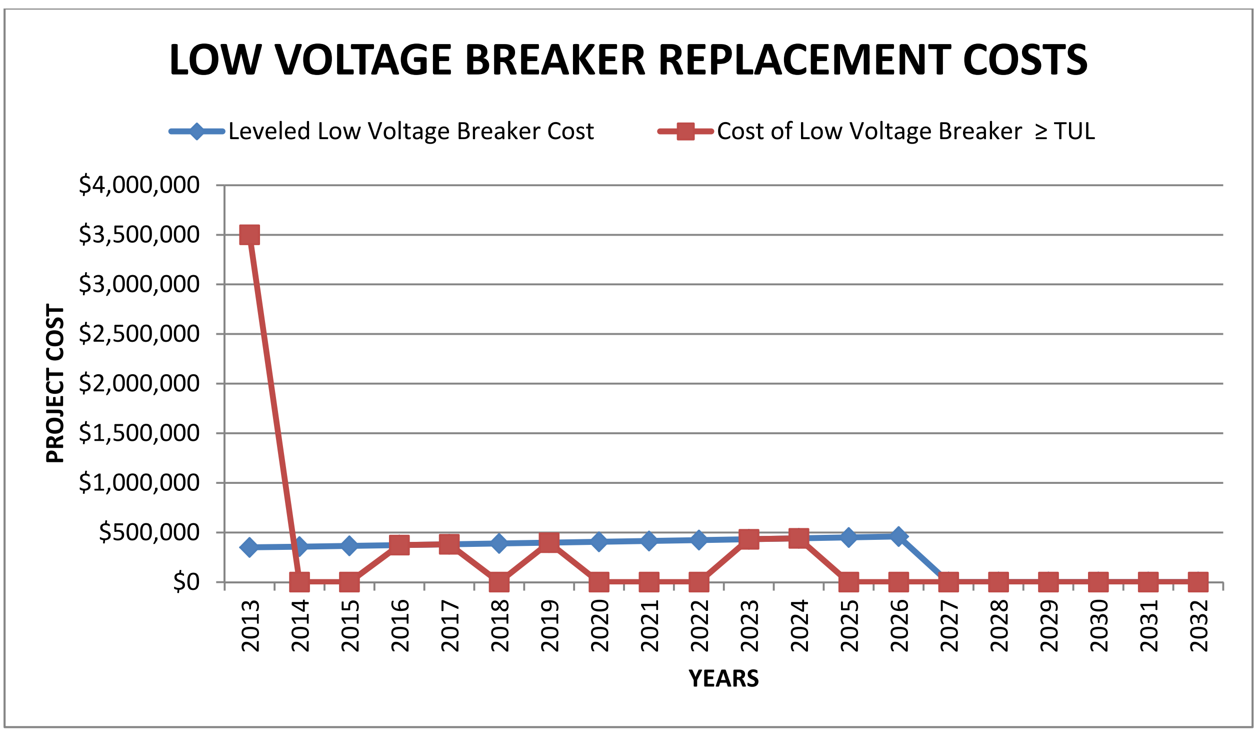


Figure 11

High Voltage Station Switches

Asset Evaluation

High voltage station switches form a small asset base. Year of manufacture ranges from 1957 to 2011 with the average age being 36 years old. OHEDI uses a Typical Useful Life (TUL) of 55 years. Based upon this timeframe, currently two high voltage station switches have exceeded the TUL of 55 years.

The following bar graph shows the quantity of high voltage station switches that will exceed this TUL within the next 20 years.

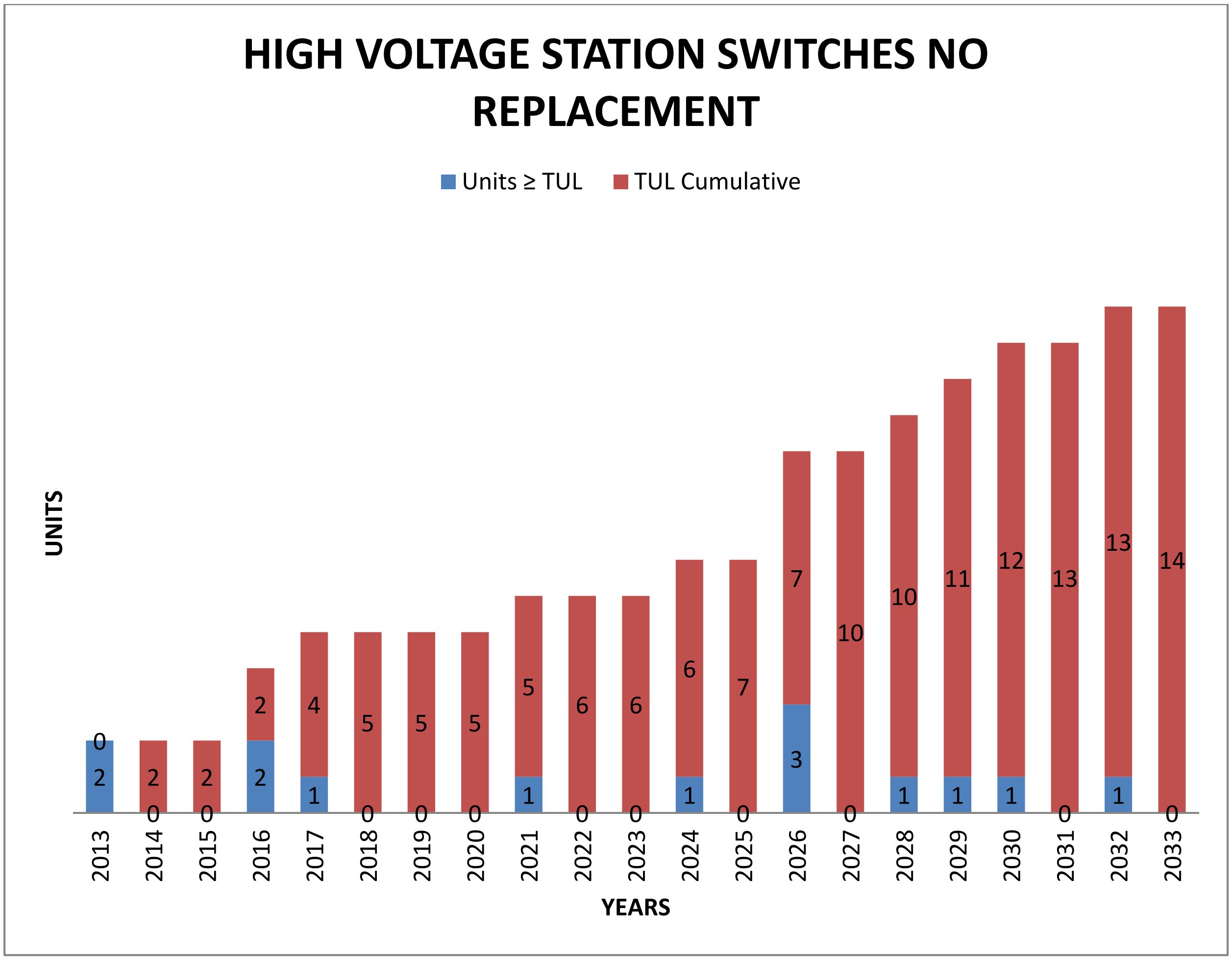


Figure 12

Investment Optimization

The station load will be reviewed to determine if it can be serviced from standard padmount switchgear. Utilizing standard padmount switchgear will reduce both material and installation cost, and allows for spare inventory in the case of equipment failure.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace one high voltage station switch in each of the following years: 2013 to 2014, 2016 to 2018, 2021, 2024, and 2026 to 2032.

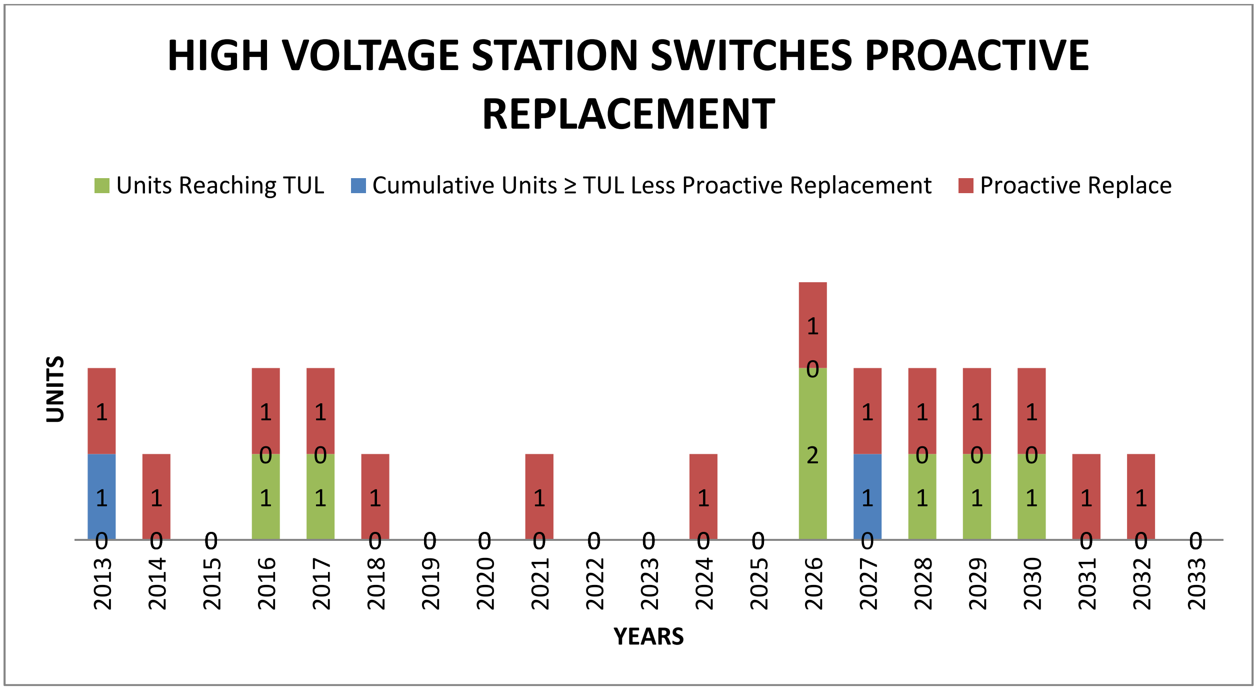


Figure 13

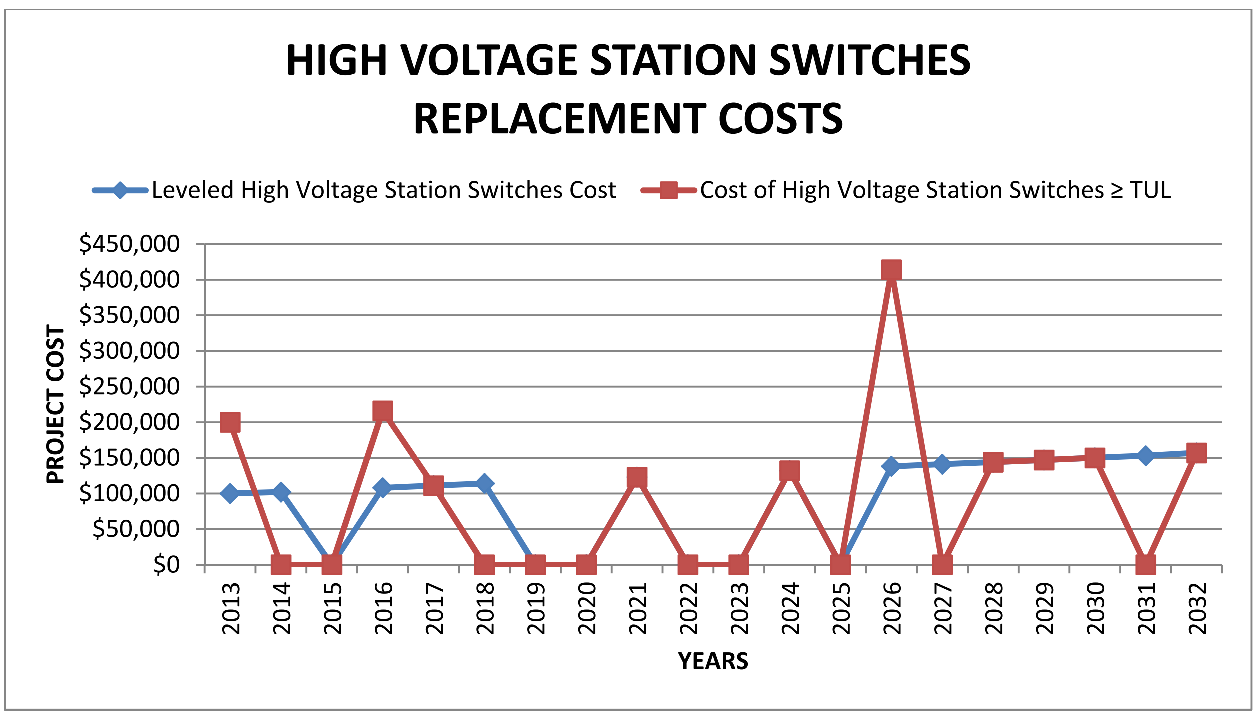


Figure 14

Overhead Distribution Transformers

Asset Evaluation

Overhead distribution transformers form a large asset base. Year of manufacture ranges from 1940 to 2012 with the average age being 24 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 508 overhead distribution transformers have exceeded the TUL of 35 years. OHEDI has chosen a run-to-failure strategy for overhead distribution transformers, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of overhead distribution transformers that will exceed this TUL within the next 20 years.

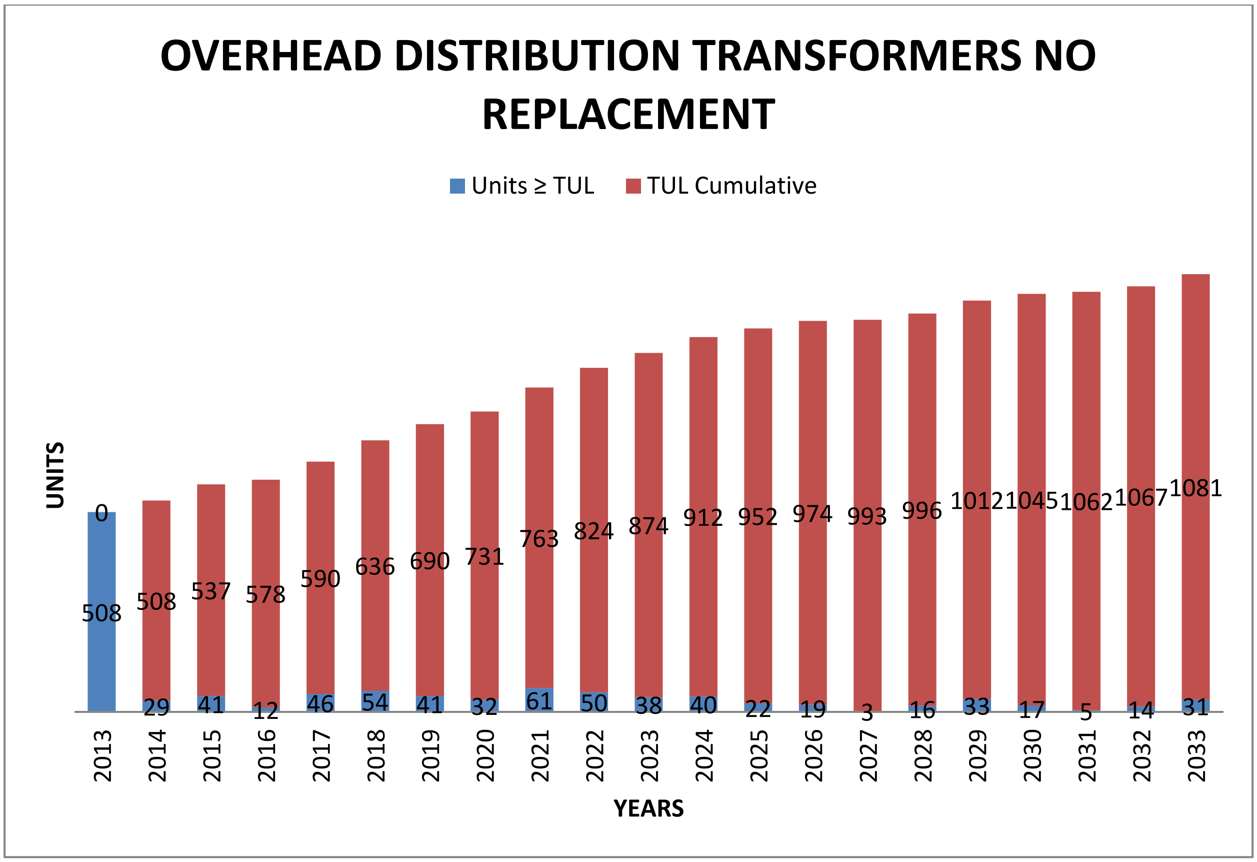


Figure 15

Investment Optimization

Prior to replacement of overhead distribution transformers the distribution area will be reviewed to determine if the transformer is still required. In the case it is not, the project will include transference of load to adjacent transformers, and decommissioning of the existing piece of equipment. Any non-standard transformers will be replaced with standard transformers where possible to lower material costs and decrease spare inventory requirements. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 53 overhead distribution transformers per year for the next 20 years.

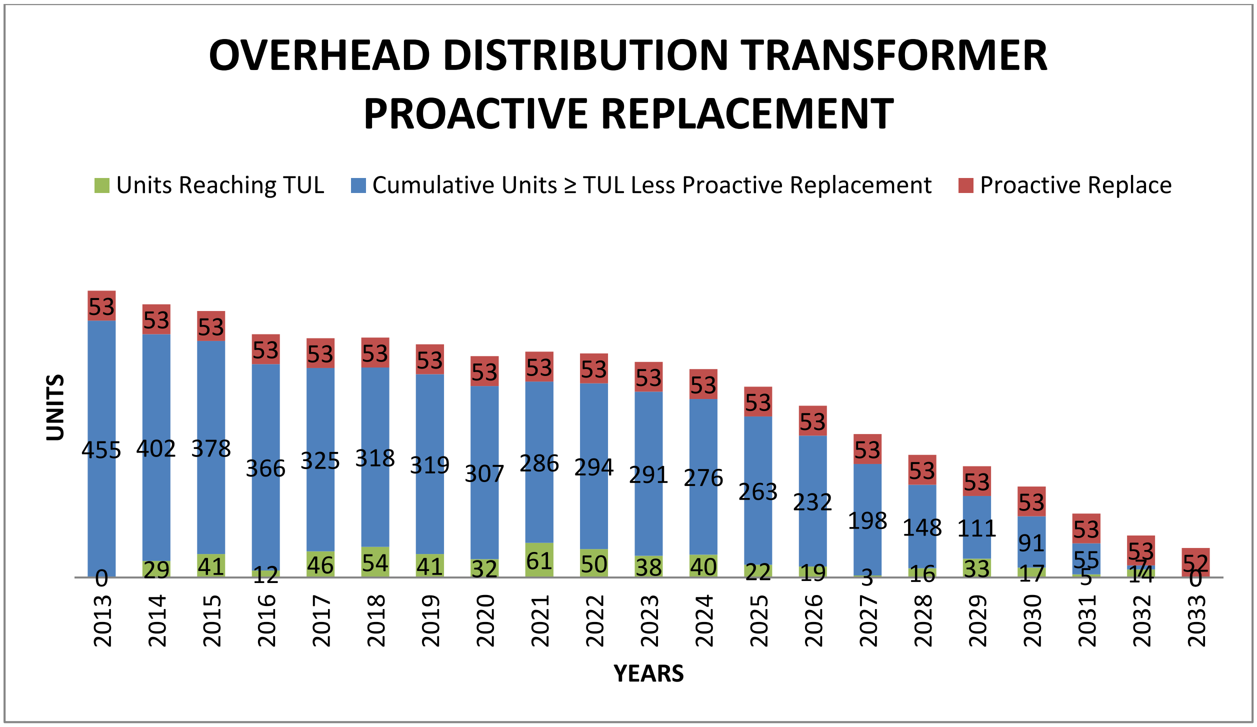


Figure 16

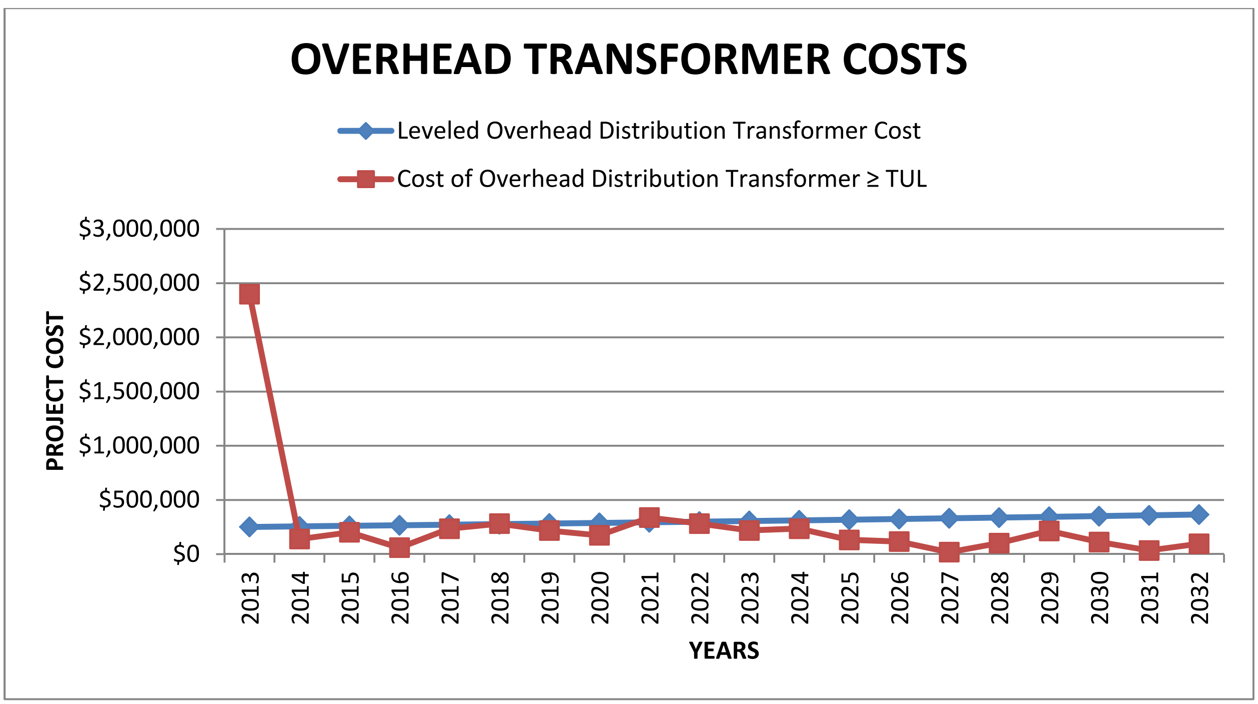


Figure 17

Padmount Distribution Transformers

Asset Evaluation

Padmount distribution transformers form a large asset base. Year of manufacture ranges from 1963 to 2012 with the average age being 17 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 45 padmount distribution transformers have exceeded the TUL of 35 years. OHEDI has chosen a run-to-failure strategy for padmount distribution transformers, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of padmount distribution transformers that will exceed this TUL within the next 20 years.

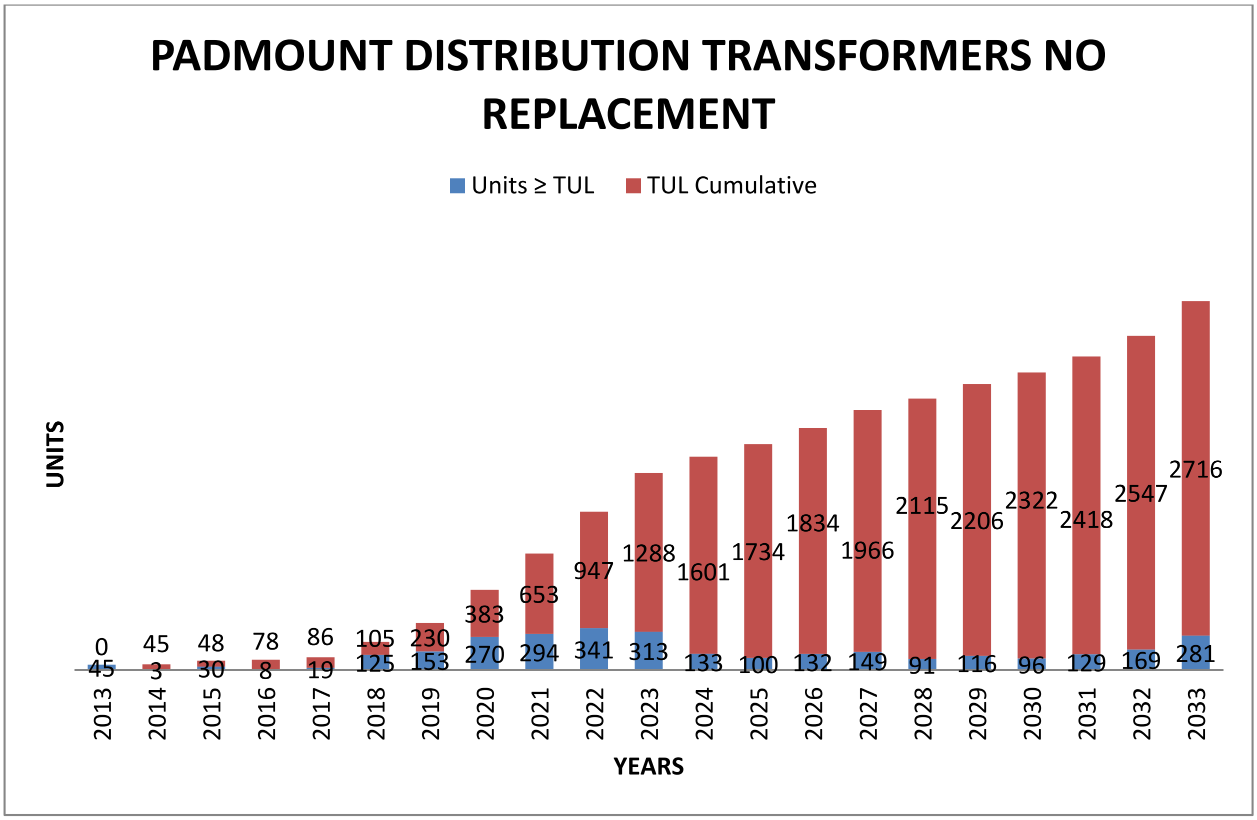


Figure 18

Investment Optimization

Prior to replacement of padmount distribution transformers the distribution area will be reviewed to determine if the transformer is still required. In the case it is not, the project will include transference of load to adjacent transformers, and decommissioning of the existing piece of equipment. Any non-standard transformers will be replaced with standard transformers where possible to lower material costs and decrease spare inventory requirements. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels. Looping of radial fed padmount distribution transformers will also be considered to improve operational costs and customer downtime.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace four padmount distribution transformers in 2013 and 2014, then 20 transformers between 2015 to 2017, with an additional 20 transformers added per year until 2030. The costs for the first five years are expected to be a higher unit cost as replacements will consist of livefront three phase padmounts, which are more costly, and require new concrete pads to be installed.

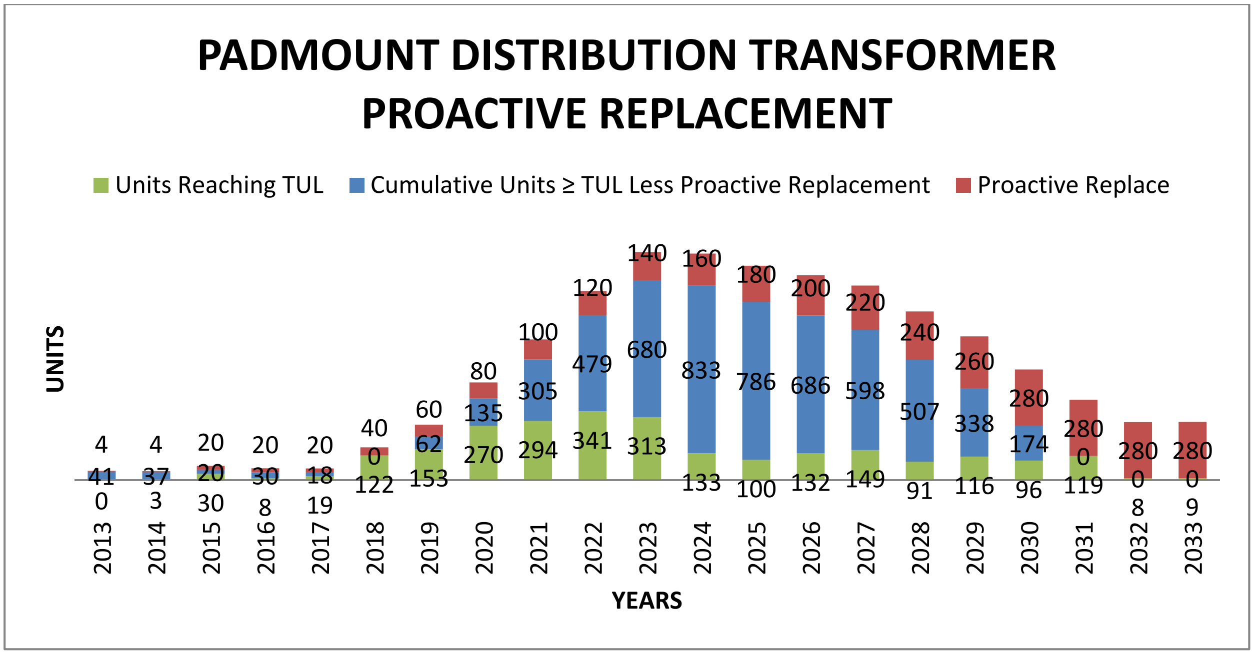


Figure 19

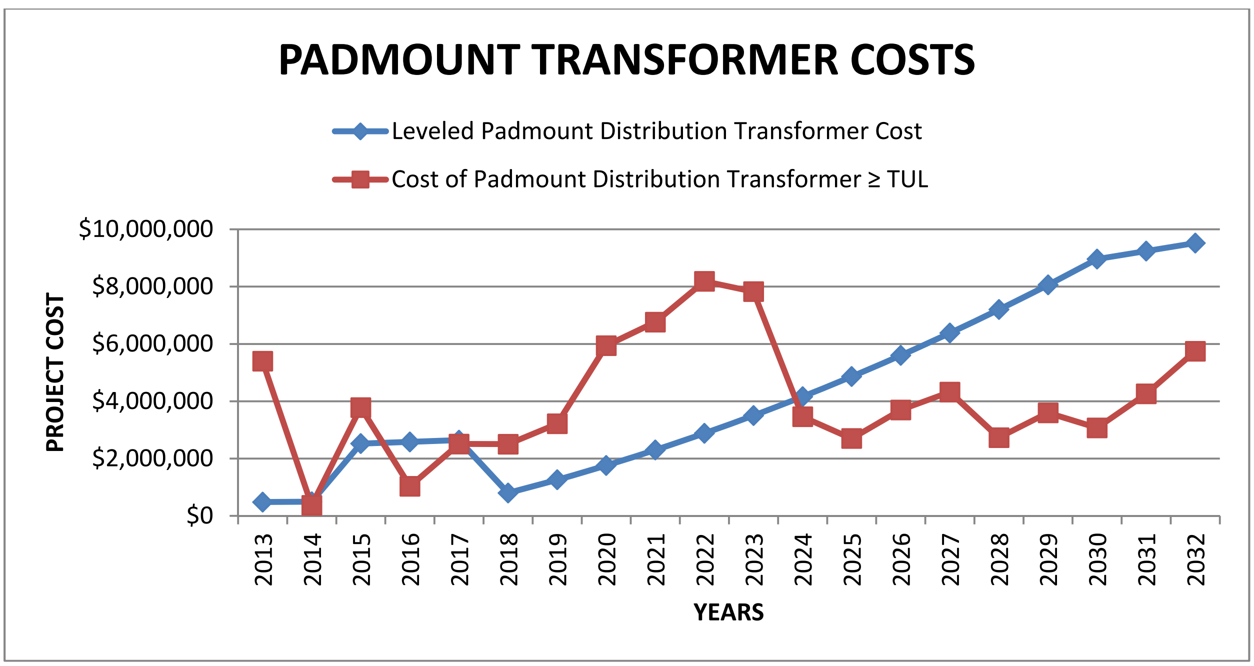


Figure 20

Submersible Distribution Transformers

Asset Evaluation

Submersible distribution transformers form a large asset base. Year of manufacture ranges from 1966 to 2012 with the average age being 17 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 107 submersible distribution transformers have exceeded the TUL of 35 years. OHEDI has chosen a run-to-failure strategy for submersible distribution transformers, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of submersible distribution transformers that will exceed this TUL within the next 20 years.

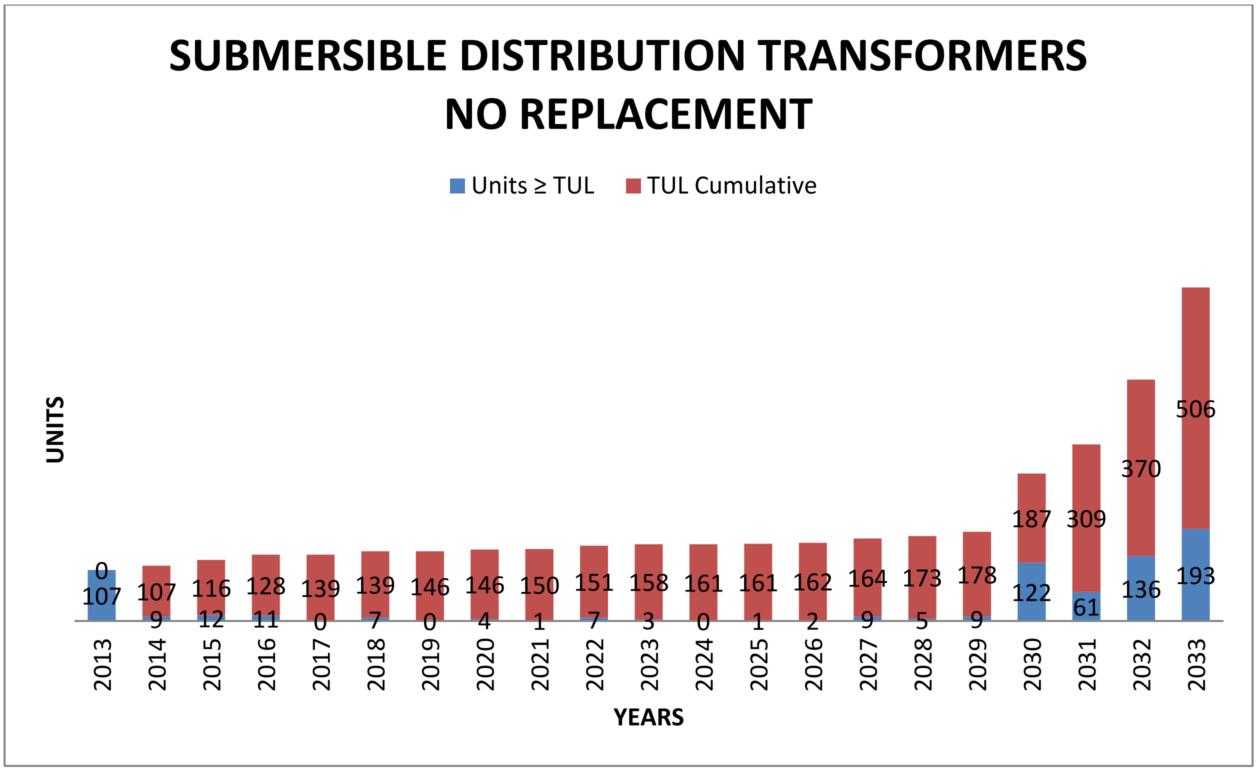


Figure 21

Investment Optimization

Prior to replacement of submersible distribution transformers the distribution area will be reviewed to determine if the transformer is still required. In the case it is not, the project will include transference of load to adjacent transformers, and decommissioning of the existing piece of equipment. Any non-standard transformers will be replaced with standard transformers where possible to lower material costs and decrease spare inventory requirements. Installation of padmount distribution transformers will be considered, as the change will allow for easier voltage conversion, as the current submersible vault structures are too small to accommodate higher voltage transformers. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 11 submersible distribution transformers per year until 2029, 50 in 2030, and an additional 50 per year until 2033.

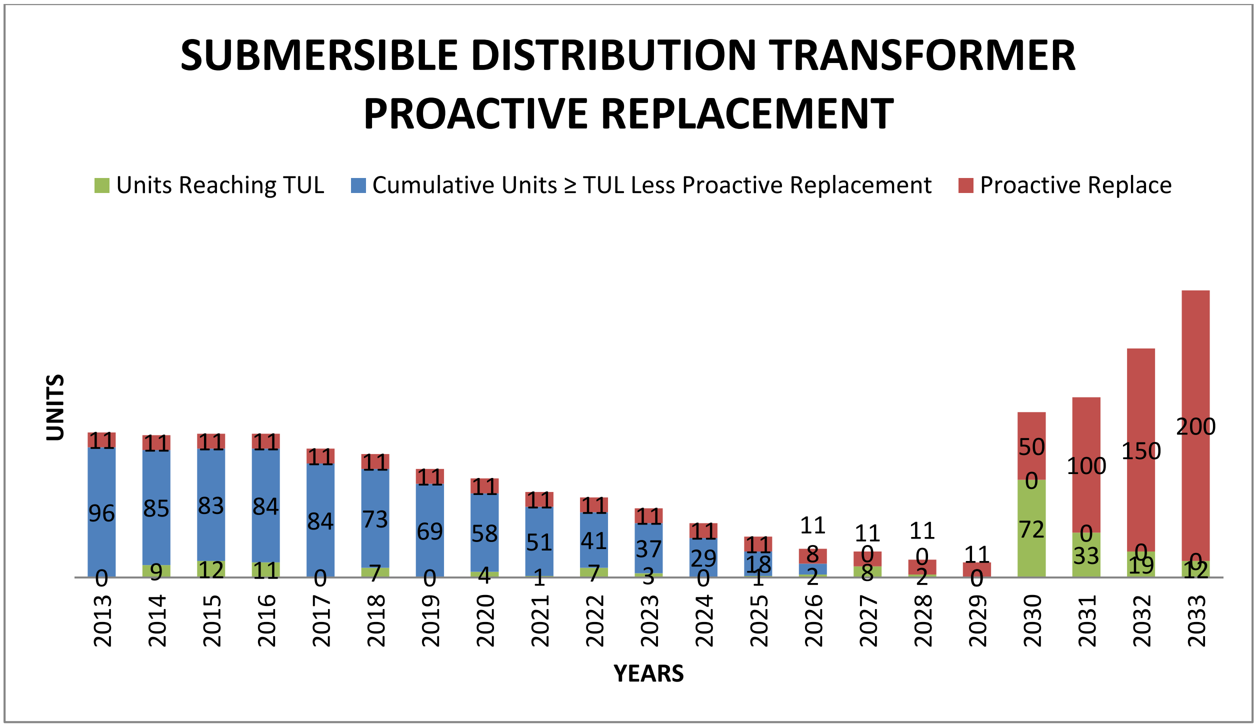


Figure 22

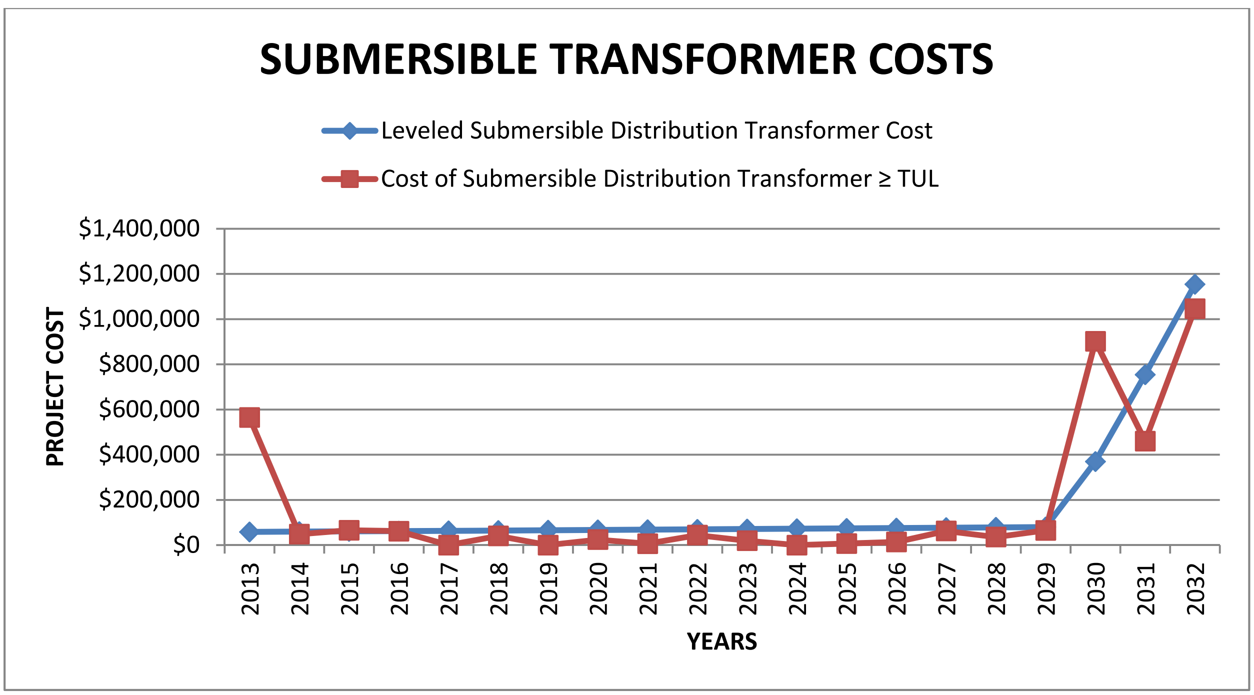


Figure 23

Vault-Style Distribution Transformers

Asset Evaluation

Vault-style distribution transformers form a large asset base. Year of manufacture ranges from 1949 to 1999 with the average age being 38 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 164 vault-style distribution transformers have exceeded the TUL of 35 years.

The following bar graph shows the quantity of vault-style distribution transformers that will exceed this TUL within the next 20 years.

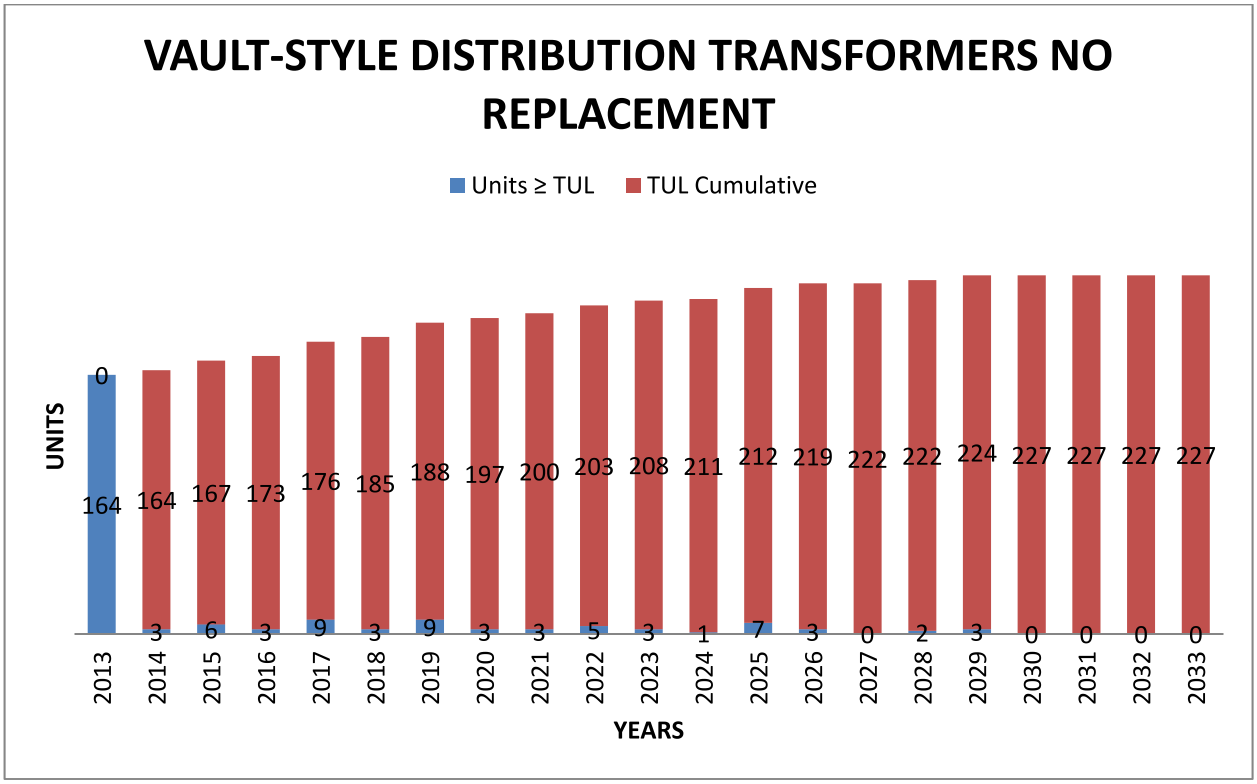


Figure 24

Investment Optimization

Prior to replacement of vault-style distribution transformers the distribution area will be reviewed to determine if the transformer is still required. In the case it is not, the project will include transference of load to adjacent transformers, and decommissioning of the existing piece of equipment. Any non-standard transformers will be replaced with standard transformers where possible to lower material costs and decrease spare inventory requirements. Installation of padmount distribution transformers located outside of the vault rooms will be considered as the change will allow easier access for operational purposes. In the case a padmount transformer cannot be installed, submersible style distribution transformers will be placed in the vault rooms. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels

20 Year Forecast

There are many assets in this category past their TUL, however these transformers are kept indoors and not subjected to weather elements. With OEB minimum inspection requirements we ensure the transformers in these rooms do not have any issues causing disruption to OHEDI customers. In order to keep distribution rates down OHEDI only plans the replacement of 9 vault-style distribution transformers per year for the next 20 years. If these transformers are found to be failing at a faster rate than they are replaced the capital replacement program will be modified accordingly.

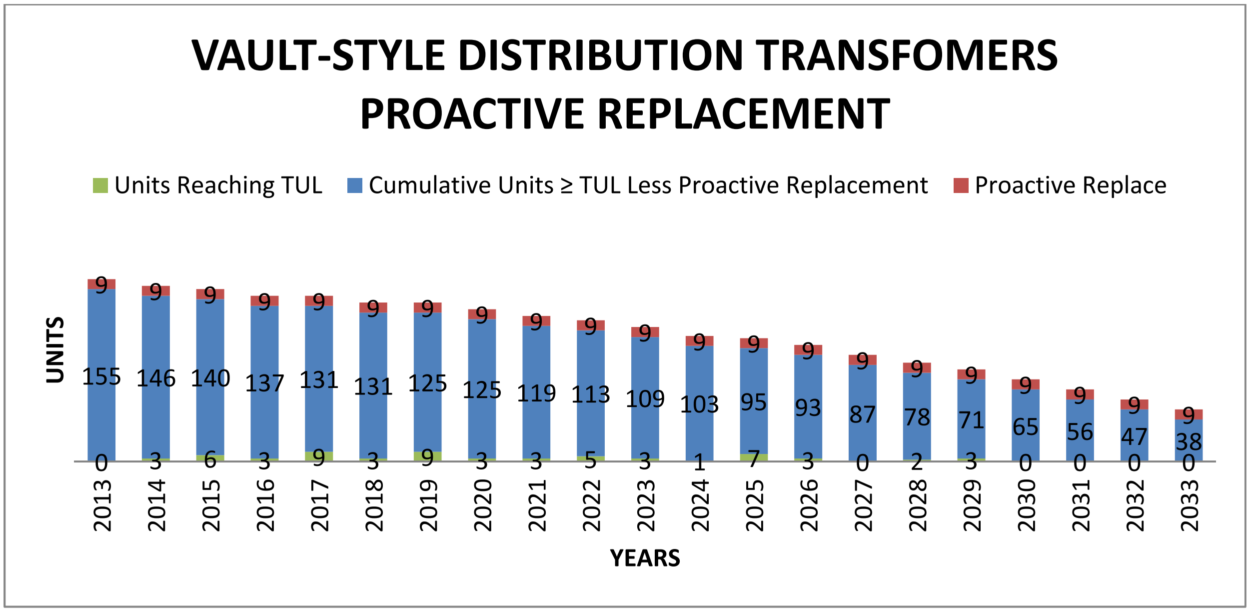


Figure 25

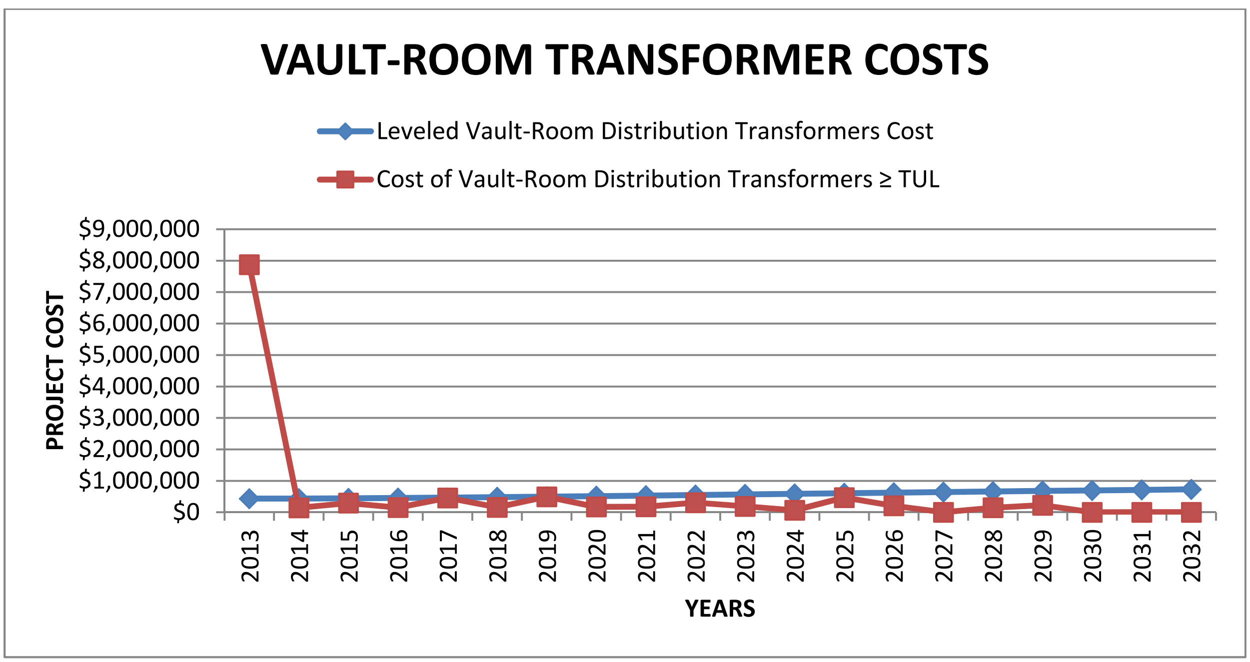


Figure 26

Padmount Switchgears

Asset Evaluation

Padmount switchgears form a large asset base. Year of manufacture ranges from 1970 to 2012 with the average age being 16 years old. OHEDI uses a Typical Useful Life (TUL) of 30 years. Based upon this timeframe, currently 11 padmount switchgears have exceeded the TUL of 30 years.

The following bar graph shows the quantity of padmount switchgears that will exceed this TUL within the next 20 years.

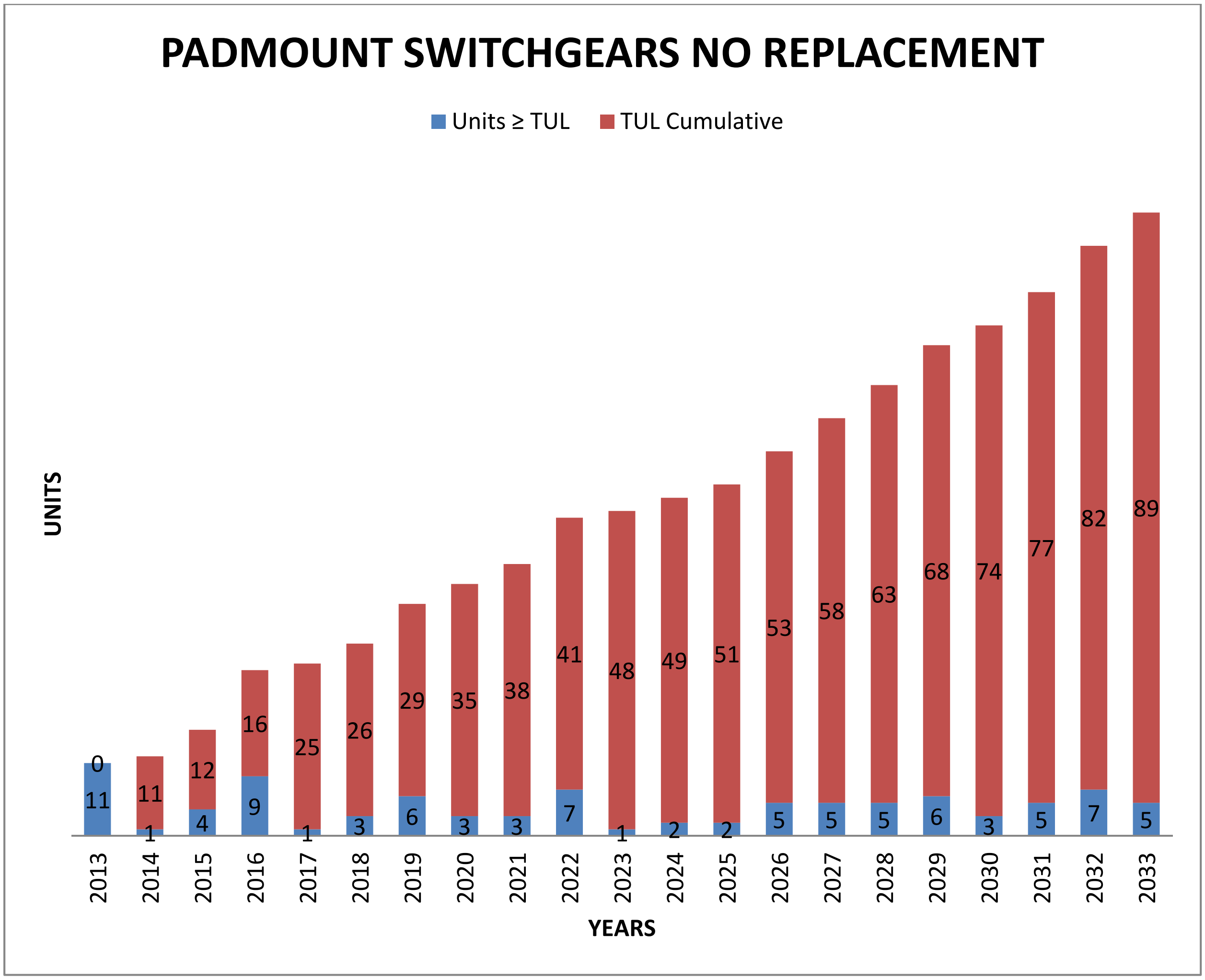


Figure 27

Investment Optimization

Any non-standard padmount switchgears will be replaced with standard padmount switchgears where possible to lower material costs and decrease spare inventory requirements. Livefront padmount switchgears will be replaced with deadfront padmount switchgears in order to lower the required maintenance costs over time. Switchgears will also be reviewed to determine if installation of motor operated controls will improve switching time and decrease operational costs.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 4 padmount switchgear per year for the next 12 years, and 5 padmount switchgear per year thereafter.

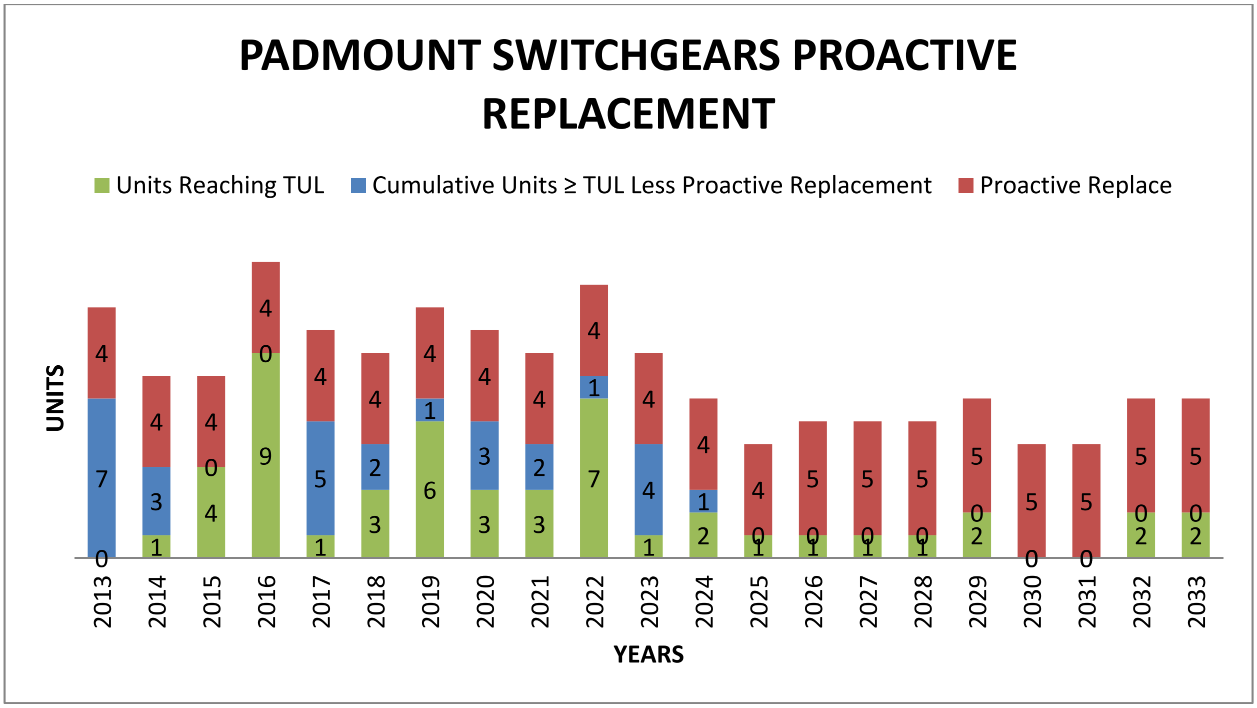


Figure 28

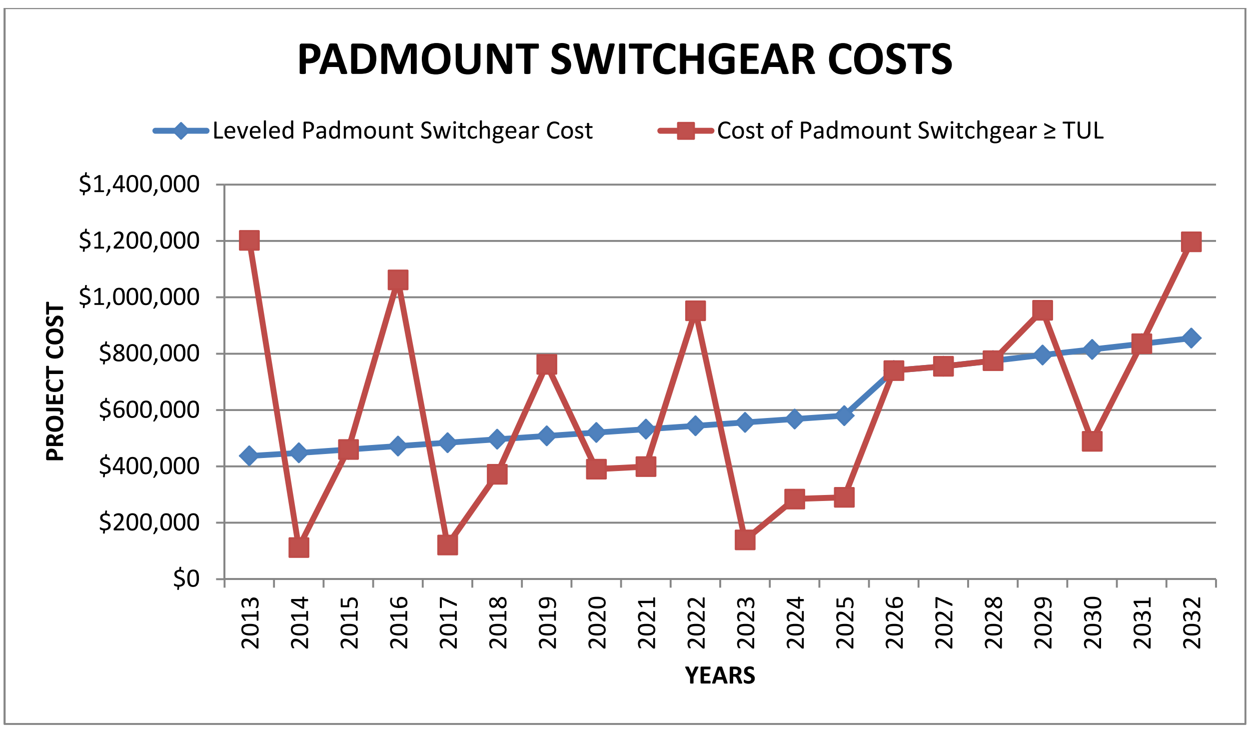


Figure 29

Vault-Style Switchgears

Asset Evaluation

Vault-style switchgears form a small asset base. Year of manufacture ranges from 1970 to 2006 with the average age being 21 years old. OHEDI uses a Typical Useful Life (TUL) of 30 years. Based upon this timeframe, currently four vault-style switchgears have exceeded the TUL of 30 years.

The following bar graph shows the quantity of vault-style switchgears that will exceed this TUL within the next 20 years.

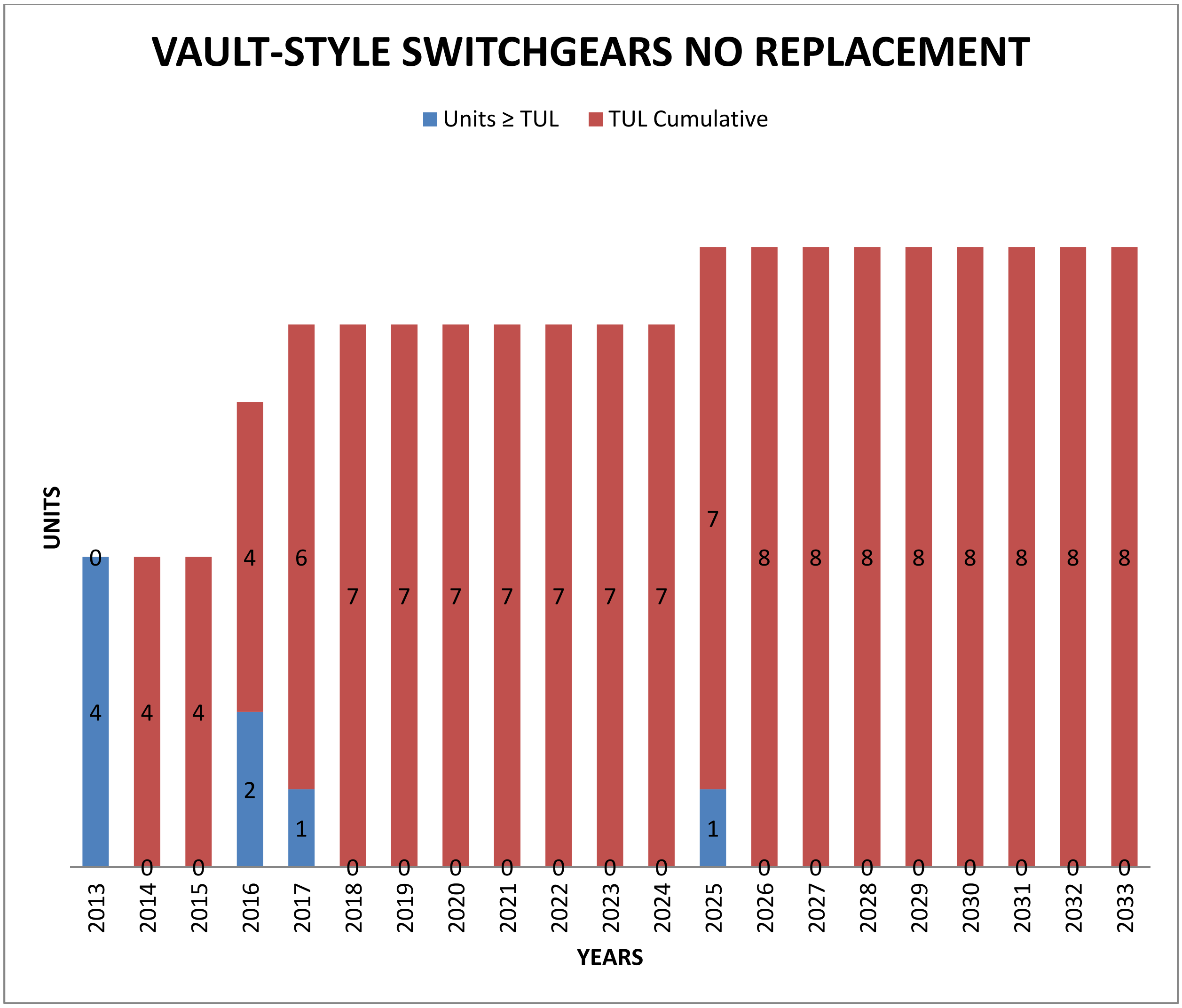


Figure 30

Investment Optimization

Any non-standard vault-style switchgears will be replaced with standard vault-style switchgears where possible to lower maintenance costs and decrease spare inventory requirements. Switchgears will also be reviewed to determine if installation of motor operated controls will improve switching time and decrease operational costs.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace one vault-style switchgear per year from 2014 to 2020 and in 2025.

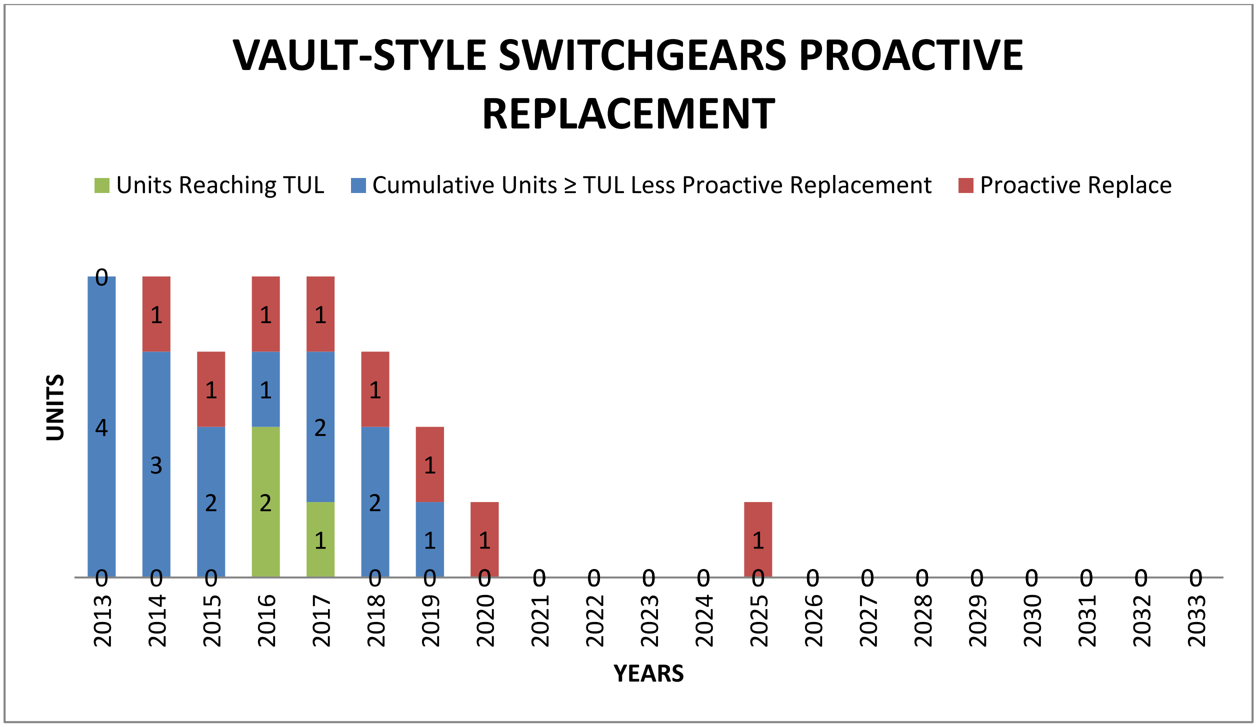


Figure 31

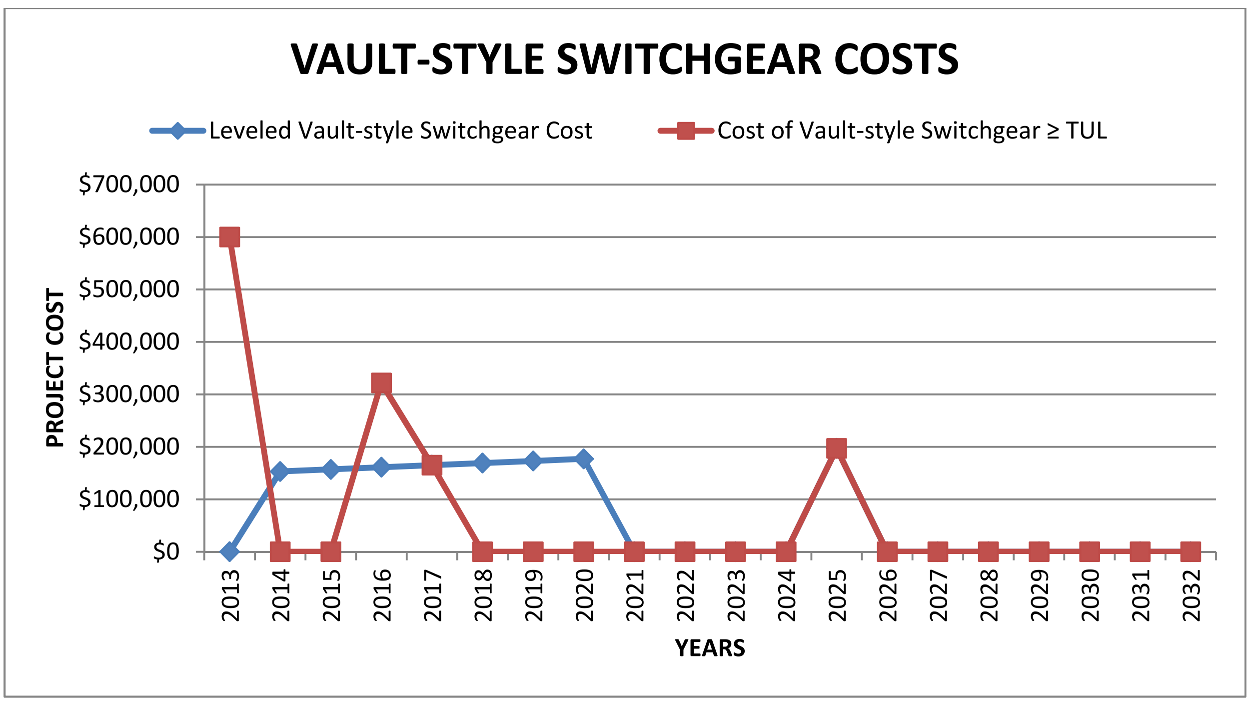


Figure 32

Gang-Operated Switches

Asset Evaluation

Gang-operated switches are switching devices used in overhead power lines. They are called gang-operated as they are single phase devices mechanically coupled and operated all at the same time. Gang-operated switches form a large asset base. Year of manufacture ranges from 1981 to 2012 with the average age being 15 years old. OHEDI uses a Typical Useful Life (TUL) of 25 years for motorized and 45 years for non-motorized. Based upon this timeframe, currently 21 gang-operated switches have exceeded the TUL of 25 or 45 years.

The following bar graph shows the quantity of gang-operated switches that will exceed this TUL within the next 20 years.

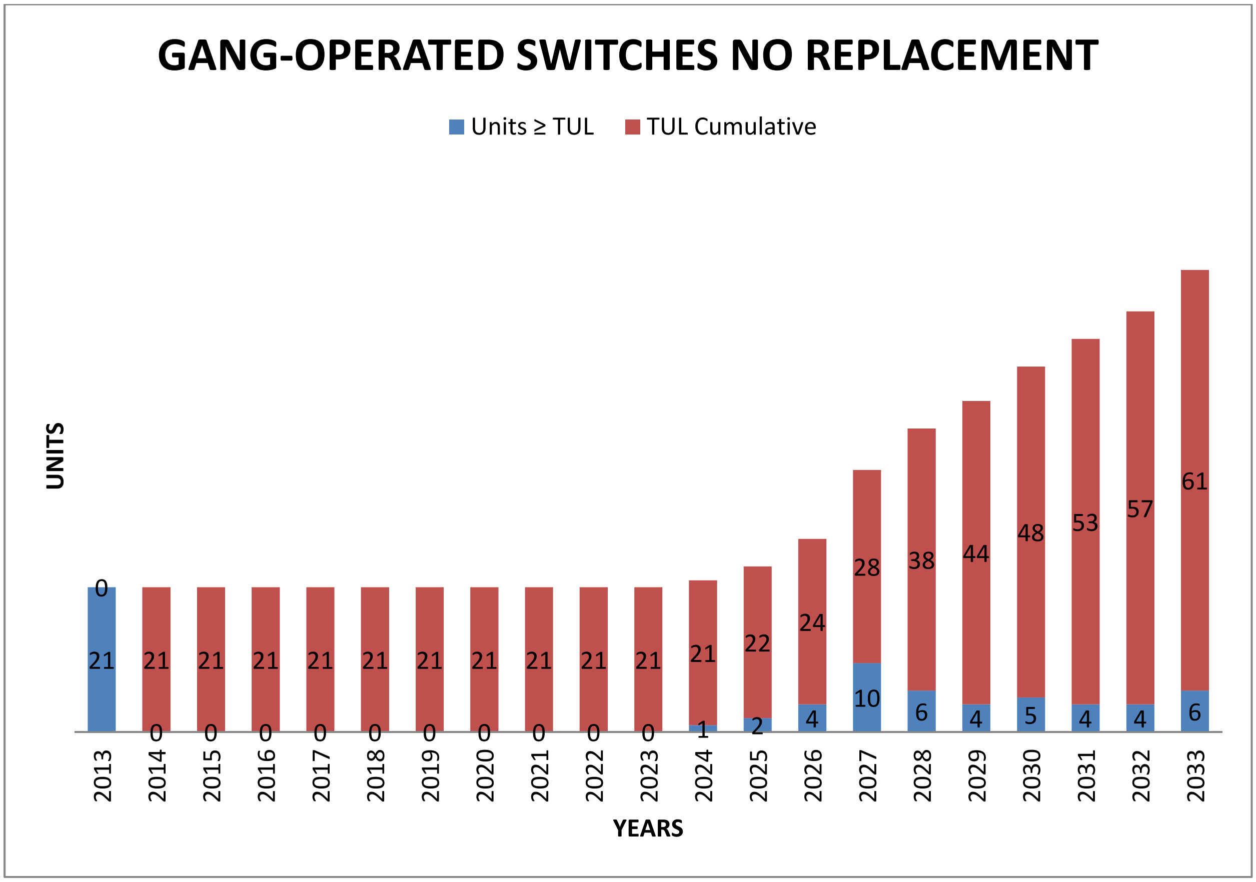


Figure 33

Investment Optimization

Prior to replacement of gang-operated switches the distribution area will be reviewed to determine if the gang-operated switch is still required. Any non-standard gang-operated switches will be replaced with standard gang-operated switches where possible to lower maintenance costs and decrease spare inventory requirements. Gang-operated switches will also be reviewed to determine if installation of motor operated controls will improve switching time and decrease operational costs.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace two gang-operated switches per year for the next 13 years and five per year thereafter.

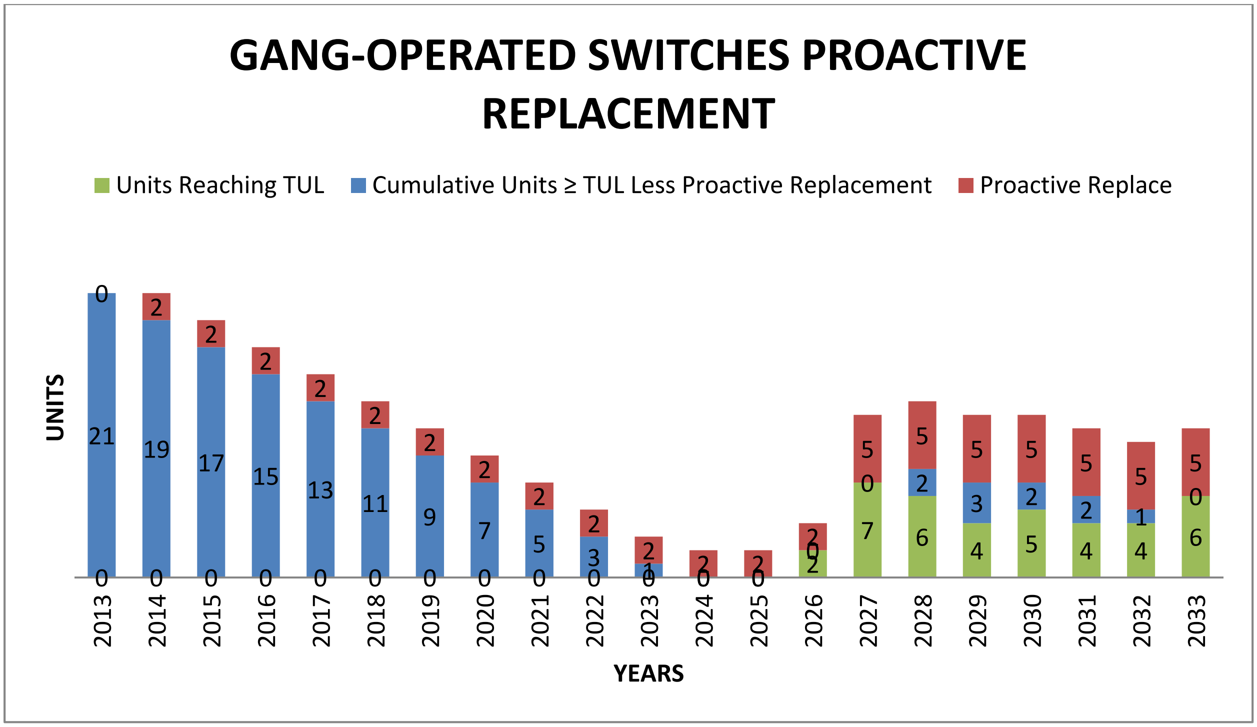


Figure 34

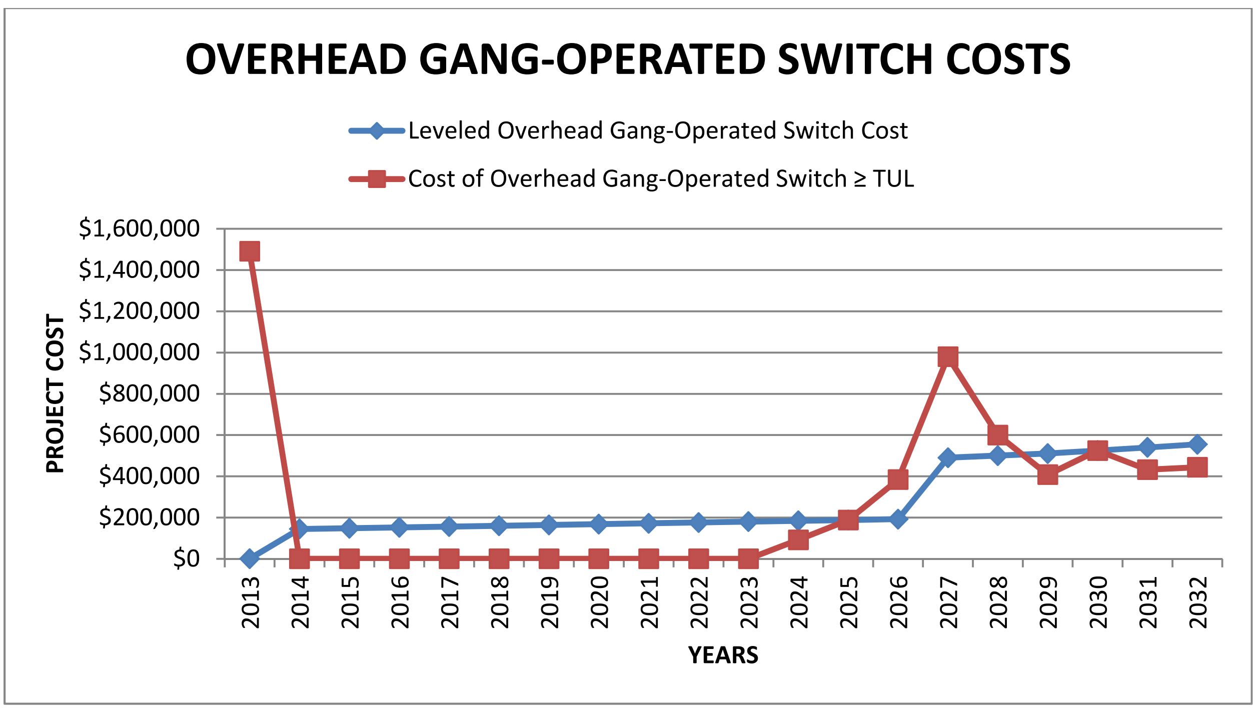


Figure 35

Overhead Primary Wires

Asset Evaluation

Overhead primary wires form a large asset base. Year of manufacture ranges from 1941 to 2012 with the average age being 47 years old. OHEDI uses a Typical Useful Life (TUL) of 60 years. Based upon this timeframe, currently 313km of overhead primary wire has exceeded the TUL of 60 years. OHEDI has chosen a run-to-failure strategy for overhead primary wires, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of overhead primary wire that will exceed this TUL within the next 20 years.

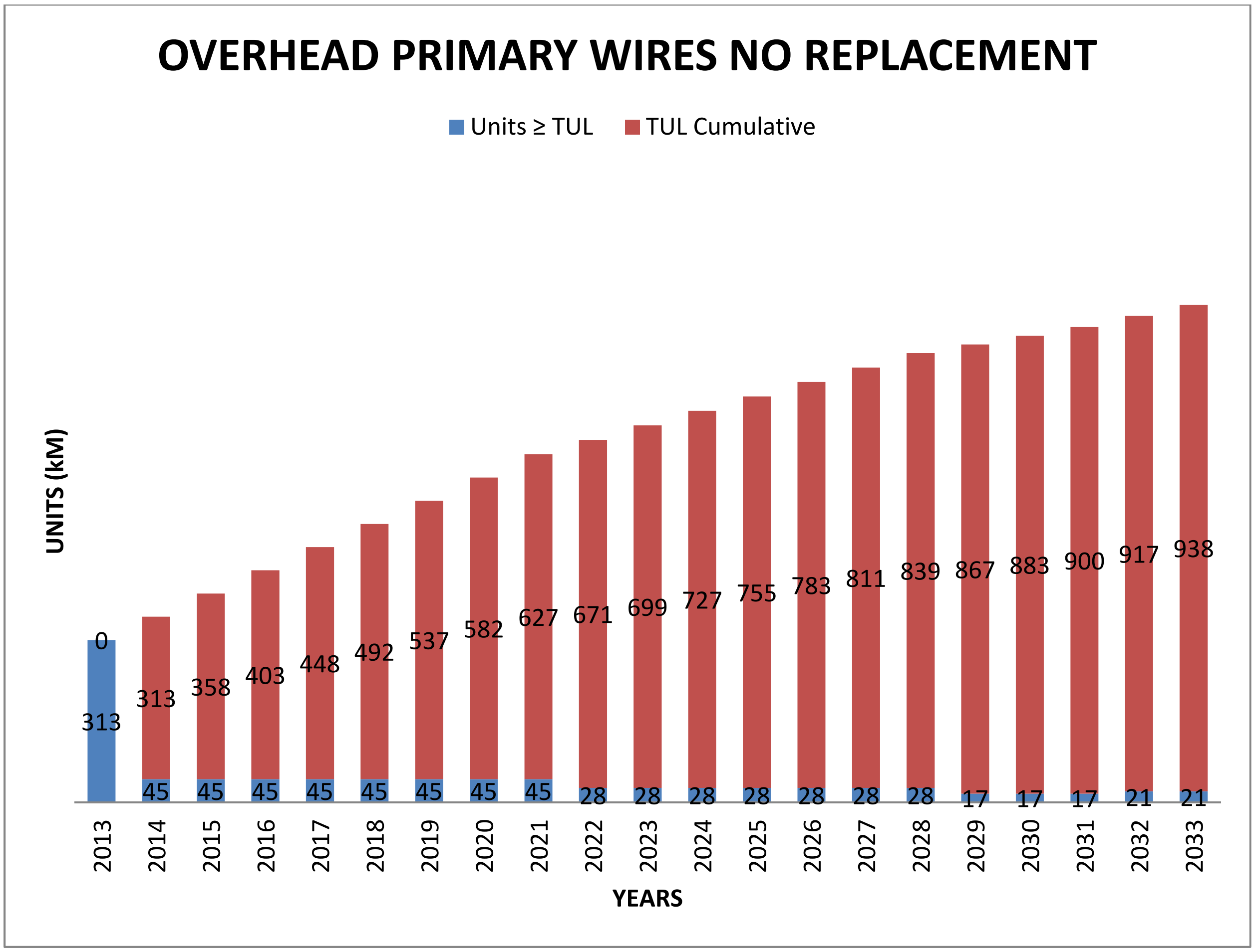


Figure 36

Investment Optimization

Any non-standard overhead primary wires will be replaced with standard wires where possible to lower material costs and decrease spare inventory requirements. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 45km of overhead primary wire per year for the next 20 years.

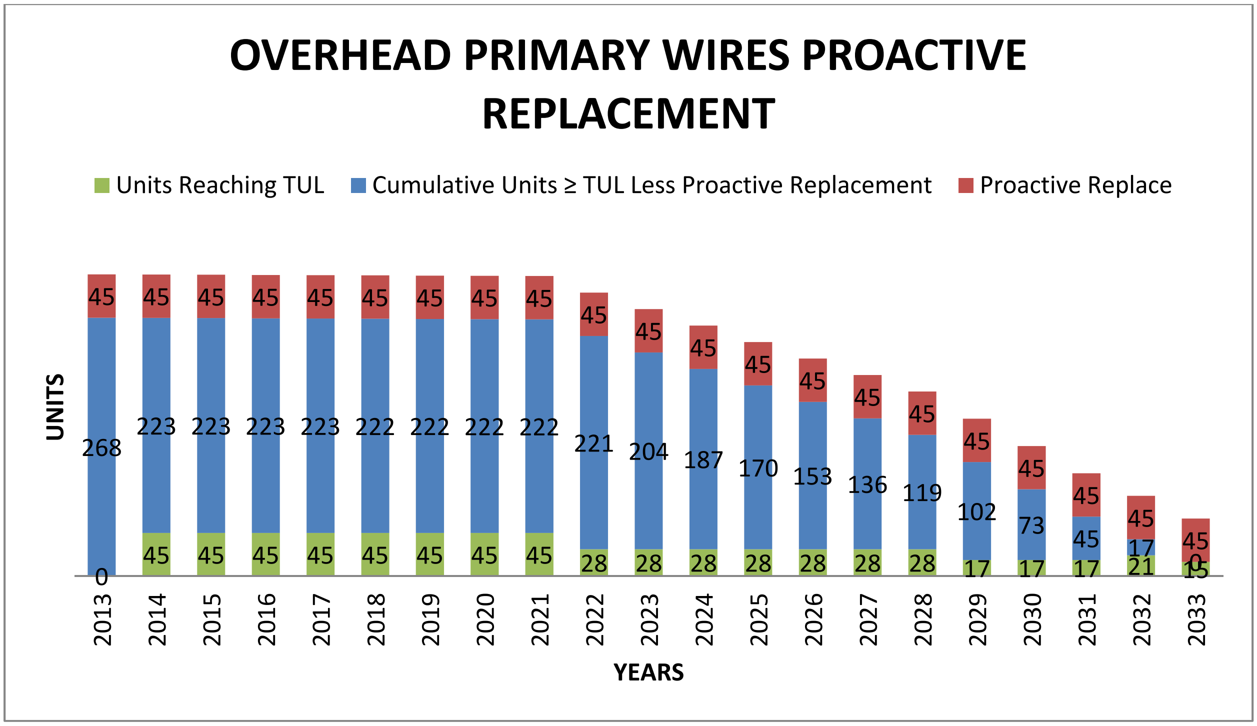


Figure 37

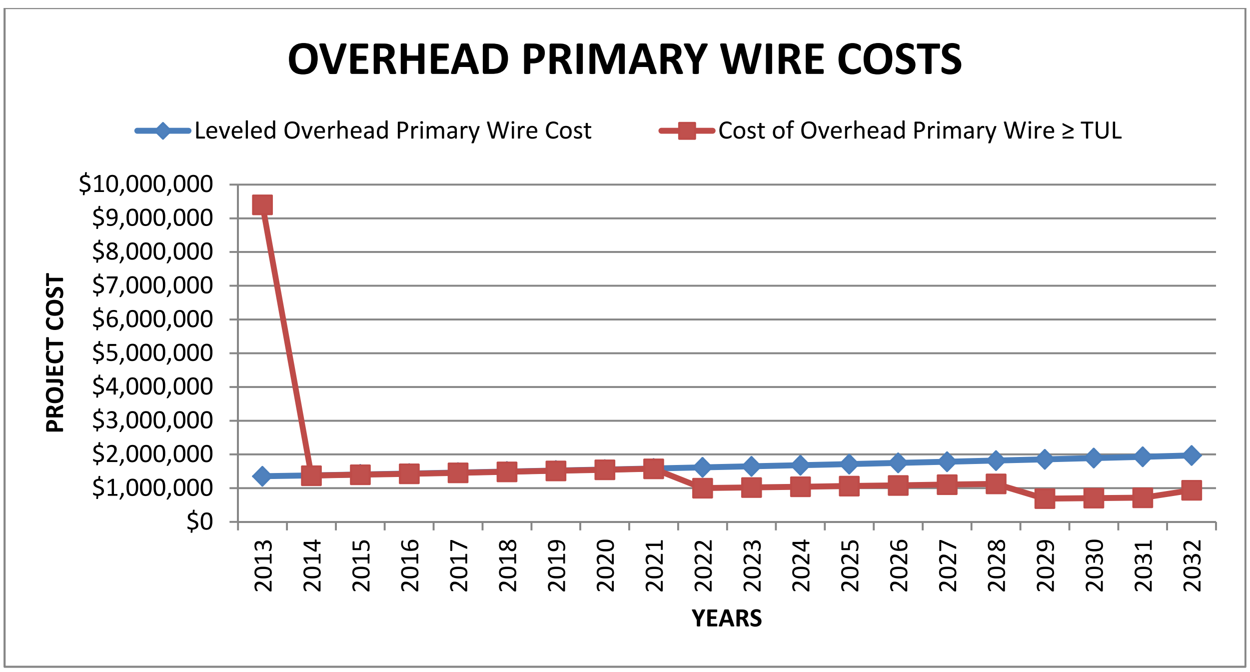


Figure 38

Underground Primary Cables

Asset Evaluation

Underground primary cables form a large asset base. Year of manufacture ranges from 1969 to 2012 with the average age being 17 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 57km of underground primary cables have exceeded the TUL of 35 years.

The following bar graph shows the quantity of underground primary cables that will exceed this TUL within the next 20 years.

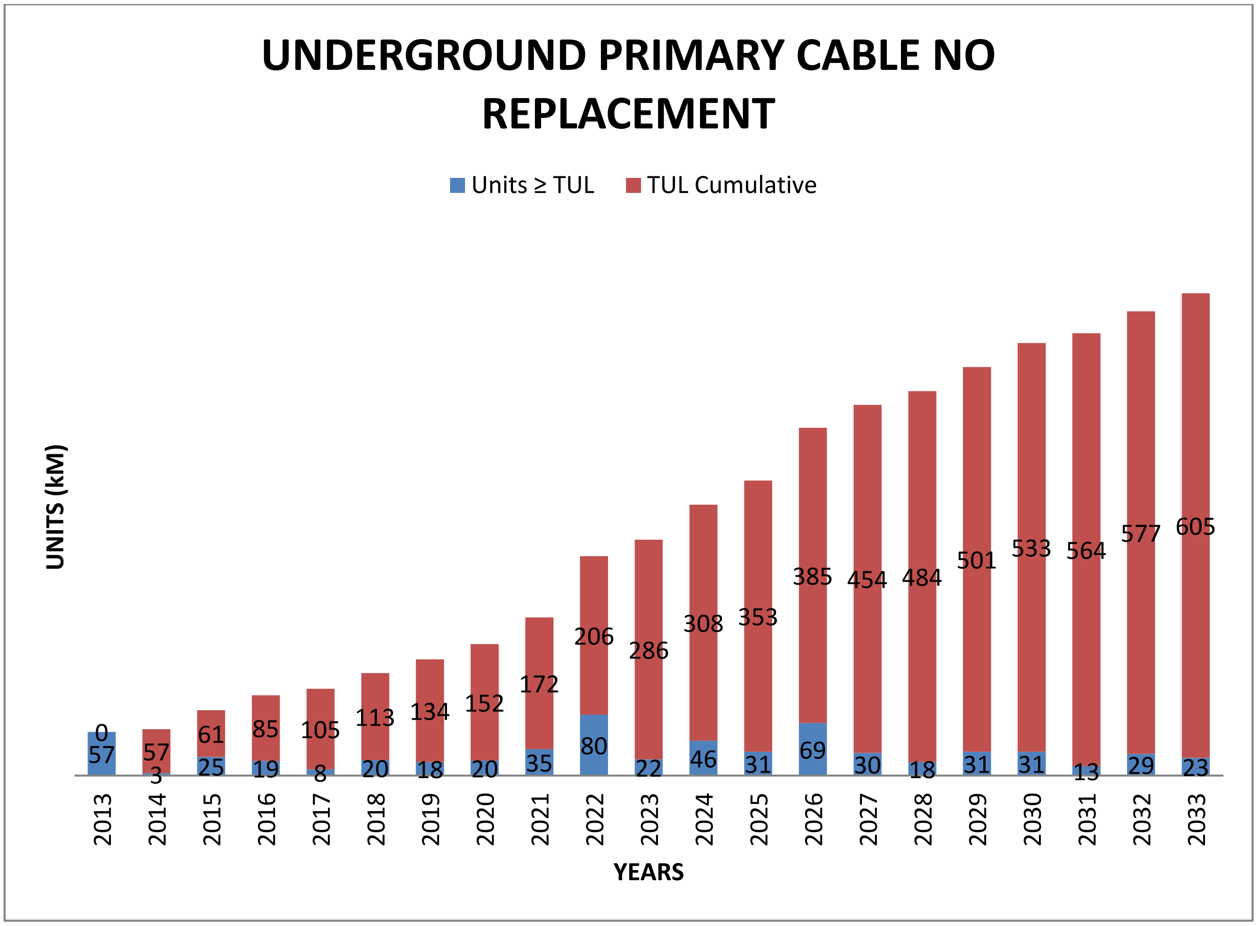


Figure 39

Investment Optimization

Any non-standard underground primary cables will be replaced with standard cables where possible to lower material costs and decrease spare inventory requirements. Areas with existing direct buried cables will be reviewed to determine if cable injection is an adequate solution to extend the useful life of the cables. For those areas where cable injection is not an option new ducts will be installed complete with new primary cables. The installation of these ducts will allow for easier replacement for future rebuilds. Voltage conversion will be considered in order to reduce losses, cost of losses, CO_2 emissions created by fossil fuel fired generating stations due to losses, and voltage drop levels.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 21km of underground primary cable per year until 2018 and one additional km per year thereafter.

OHEDI predicts the capital expenditure required in this area may increase even more due to increasing failures of the underground primary cables. Failure investigation is being performed and based upon the results OHEDI may determine to expedite the replacement of these cables sooner than their TUL to mitigate operational expenditures.

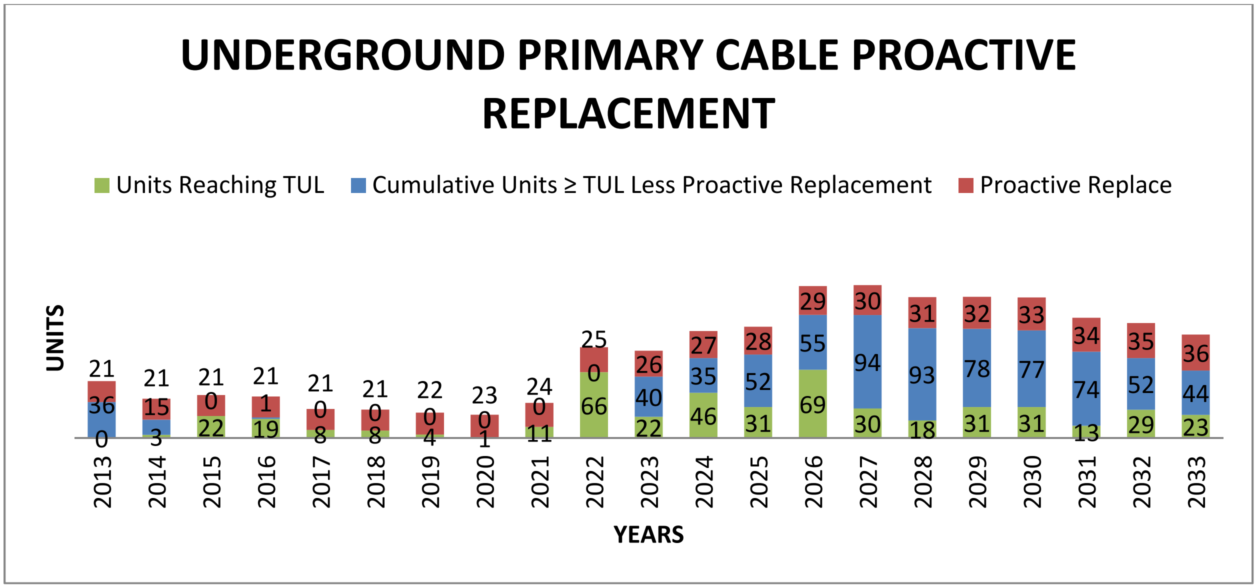


Figure 40

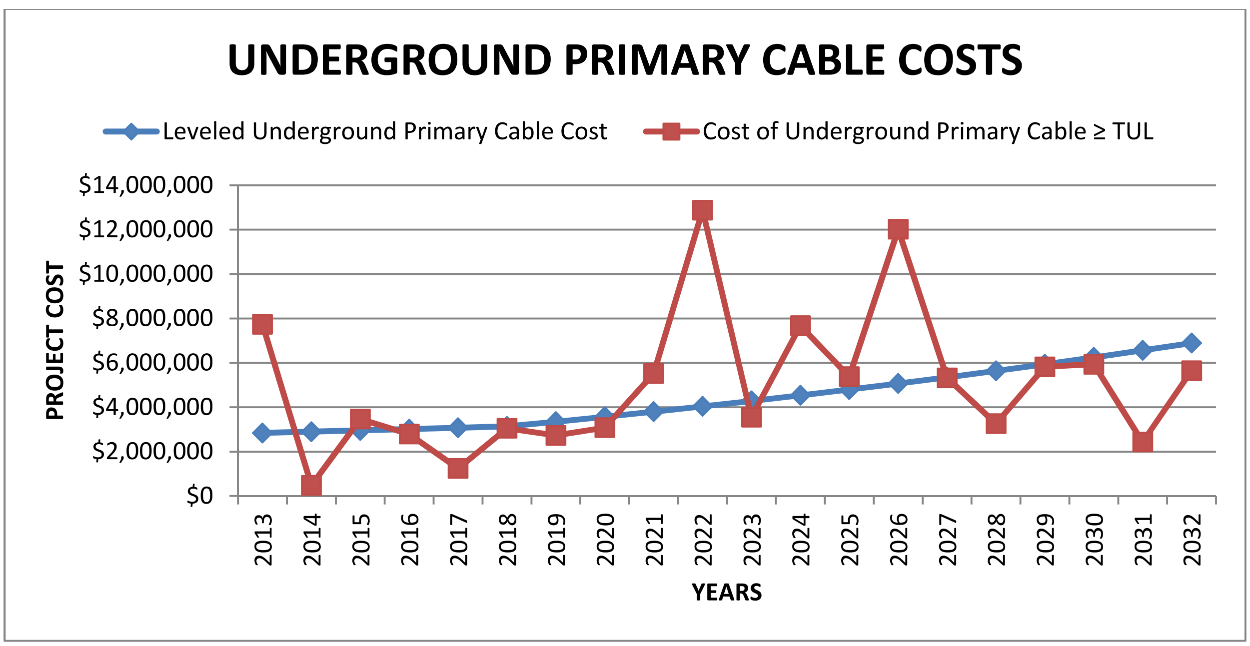


Figure 41

Poles

Asset Evaluation

Poles form a large asset base. Year of manufacture ranges from 1941 to 2012 with the average age being 26 years old. OHEDI uses a Typical Useful Life (TUL) of 45 years. Based upon this timeframe, currently 2059 poles have exceeded the TUL of 45 years.

The following bar graph shows the quantity of poles that will exceed this TUL within the next 20 years.

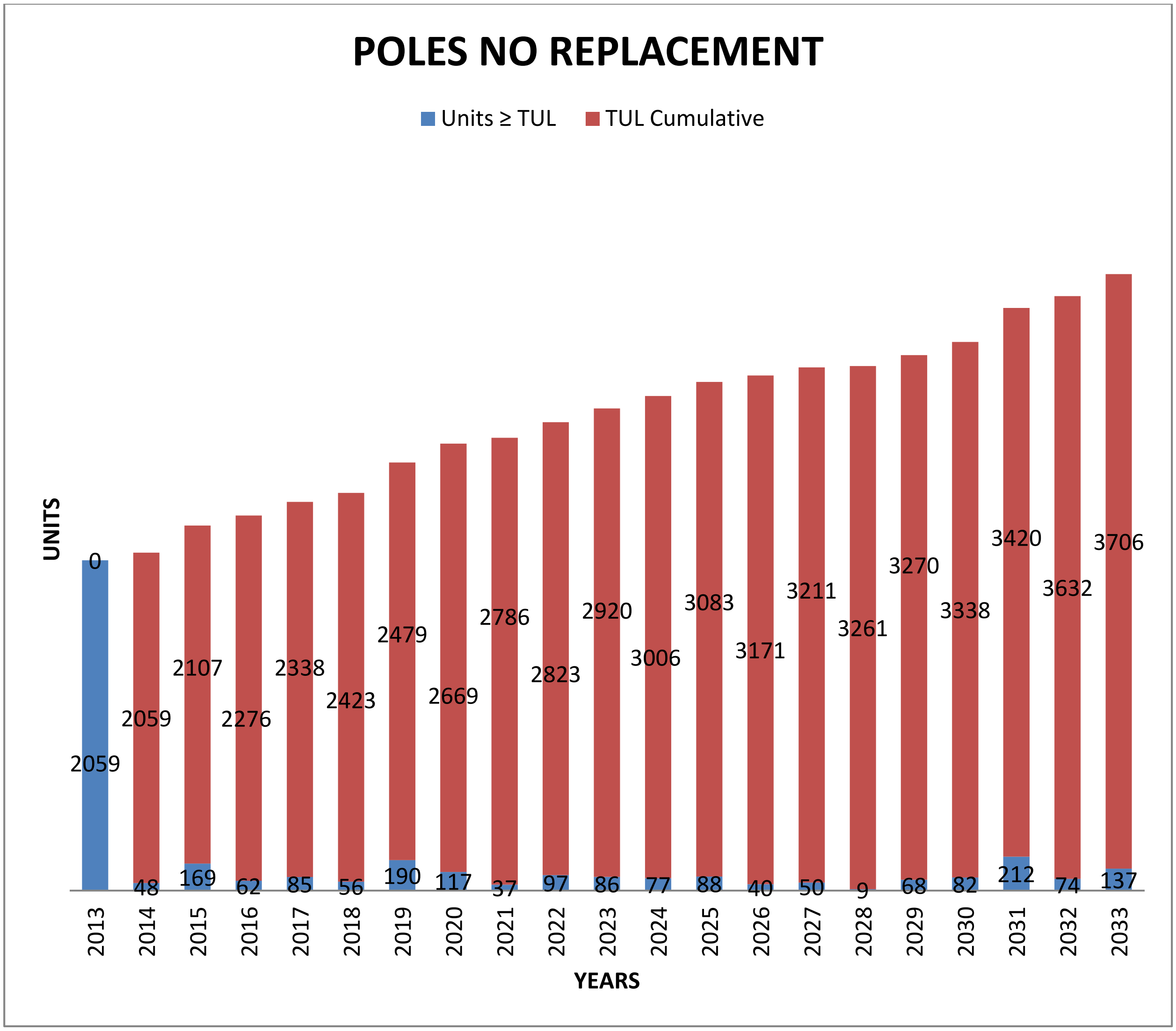


Figure 42

Investment Optimization

Prior to replacement of poles, a review is completed to determine the size and type of new pole to be installed. Future area requirements are taken into account in order to proactively increase the height of poles when required. Any non-standard poles will be replaced with standard poles where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

There are many assets in this category past their TUL, however these poles are subject to a rigorous inspection and treatment program once every six years to keep them from failing and catch those assets in a mode of failure before they do fail. In order to keep distribution rates down, OHEDI forecasts the requirement to replace 183 poles per year for the next 20 years. A number of these poles are typically replaced due to findings from the system-wide wood pole inspection program. The others are replaced due to a combination of required replacement for overhead rebuild projects, or infill service upgrades.

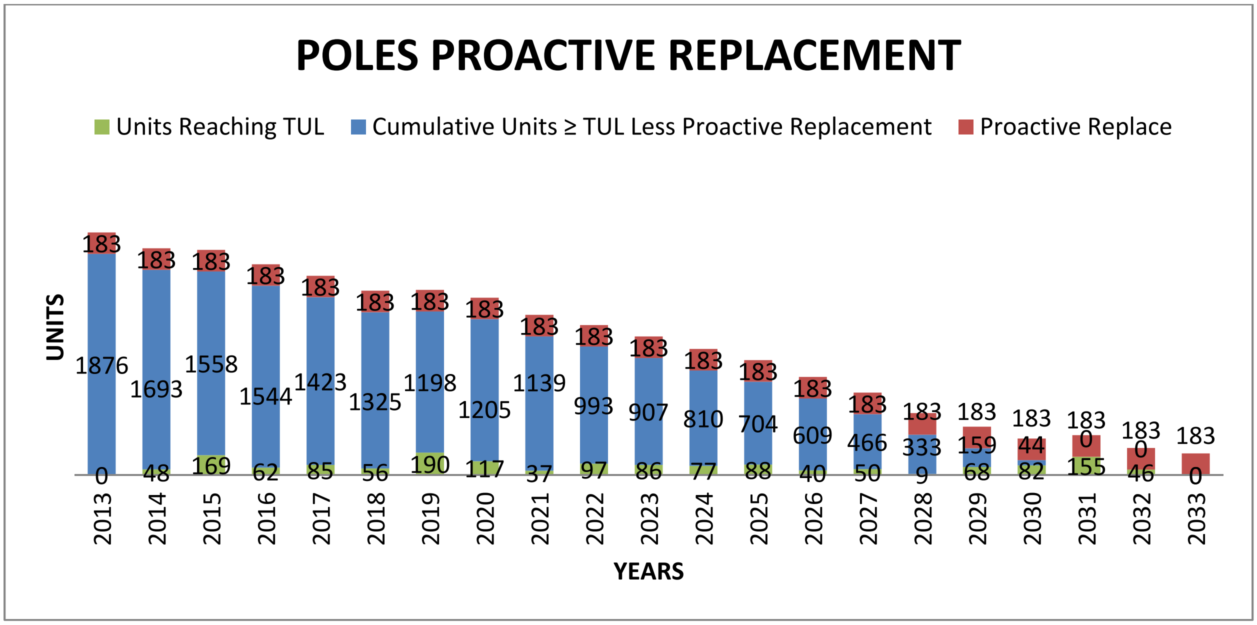


Figure 43

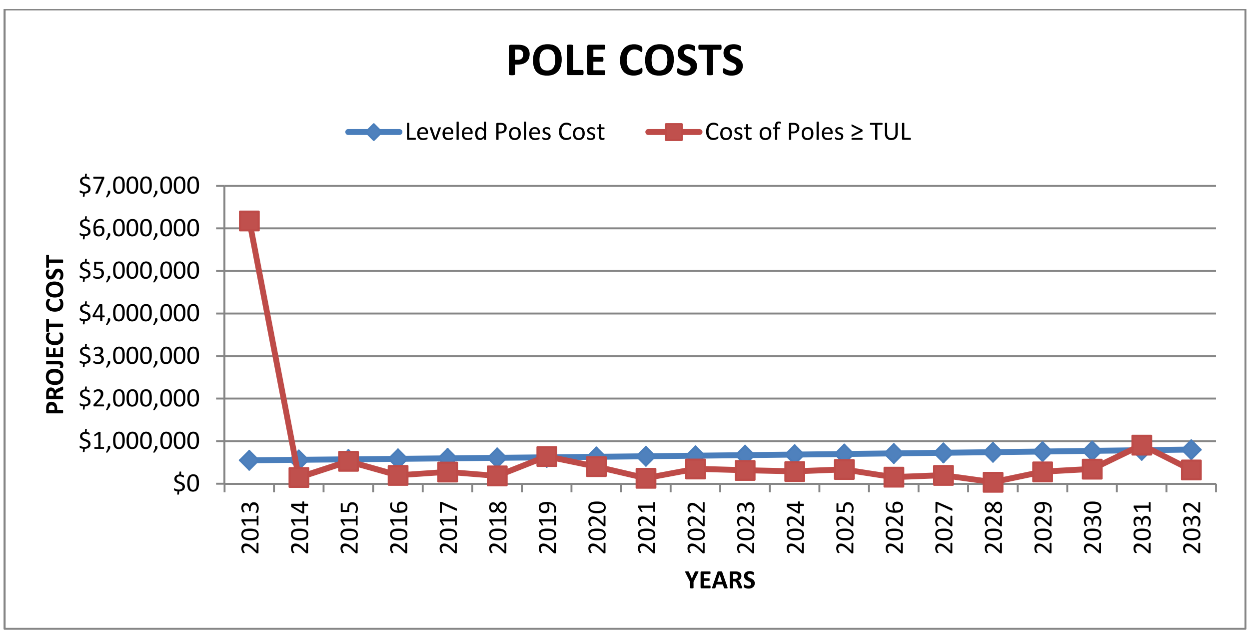


Figure 44

Overhead Secondary Wire

Asset Evaluation

Overhead secondary wires form a large asset base. Year of manufacture ranges from 1941 to 2012 with the average age being 51 years old. OHEDI uses a Typical Useful Life (TUL) of 60 years. Based upon this timeframe, currently 177km of overhead secondary wire has exceeded the TUL of 60 years. OHEDI has chosen a run-to-failure strategy for overhead secondary wire, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of overhead secondary wire that will exceed this TUL within the next 20 years.

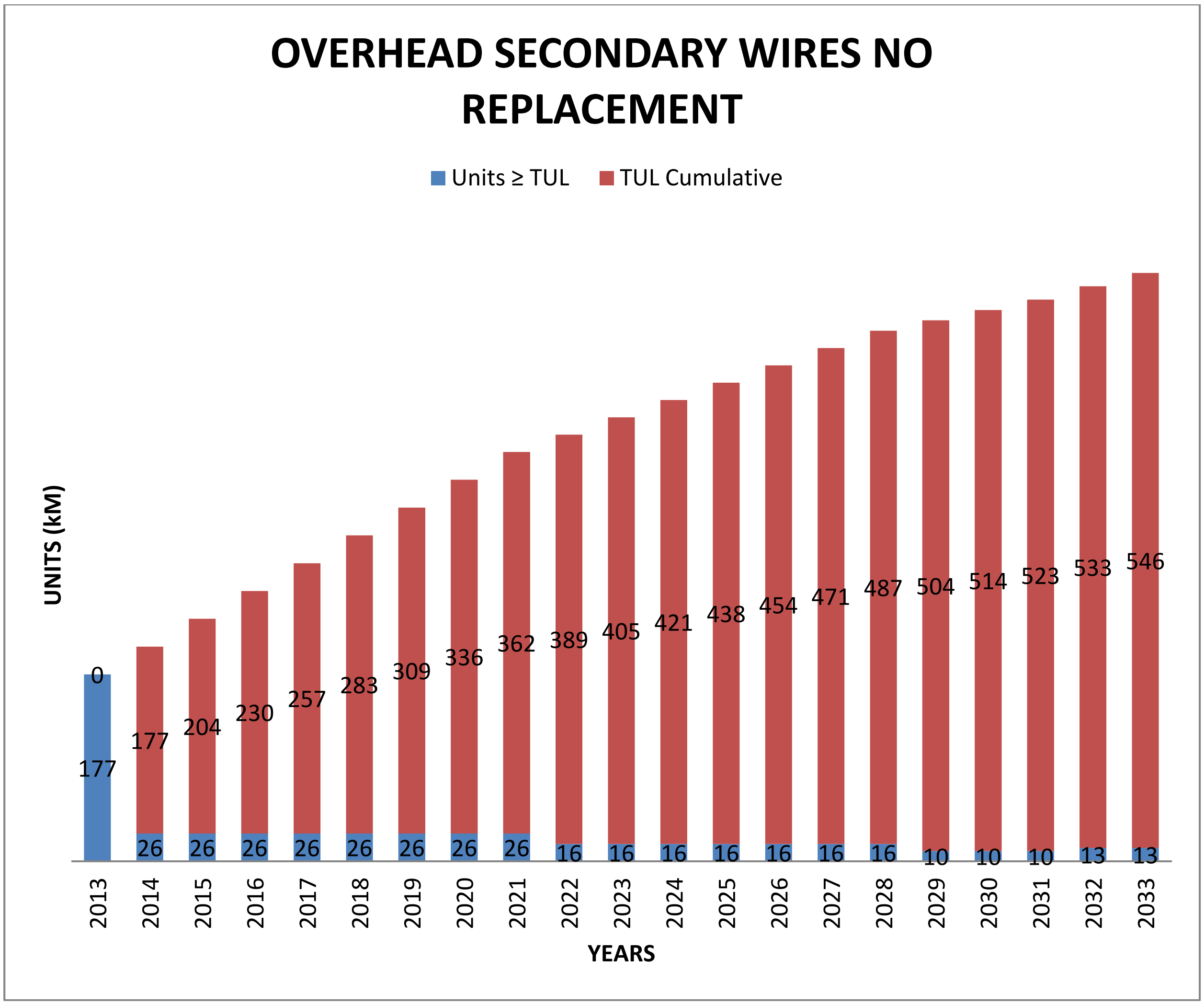


Figure 45

Investment Optimization

Any non-standard overhead secondary wires will be replaced with standard wires where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 26km of overhead secondary wire per year for the next 20 years.

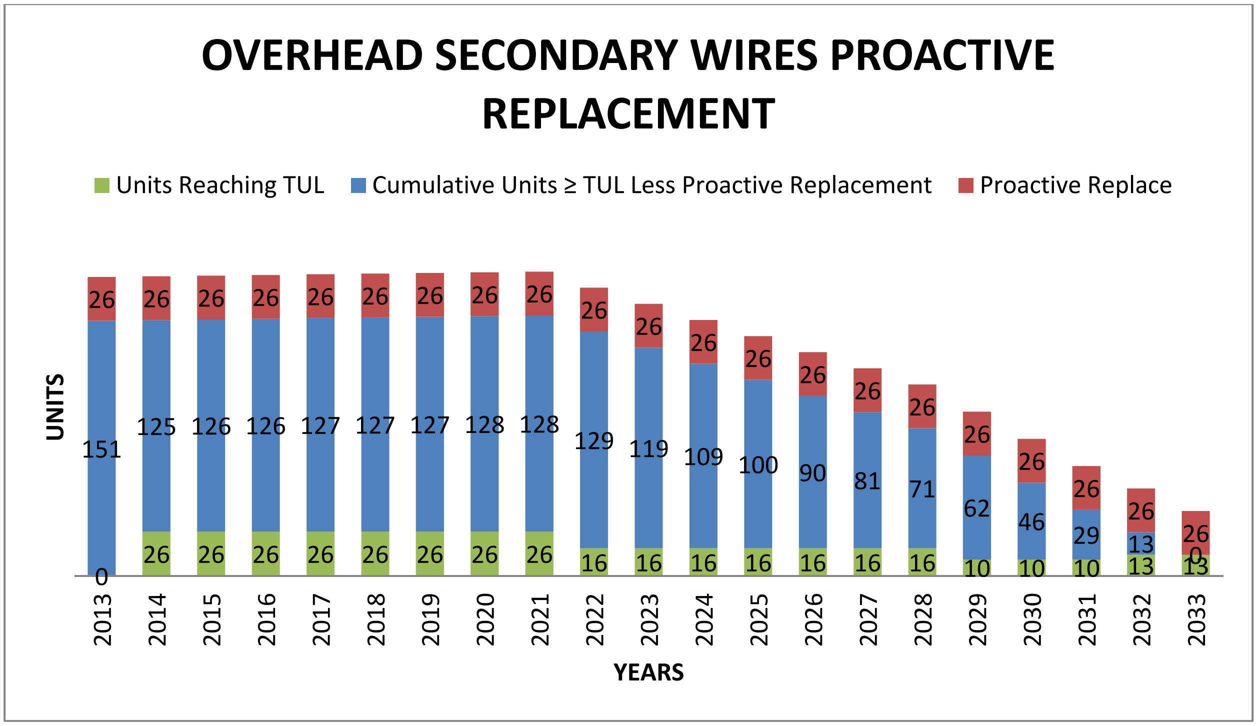


Figure 46

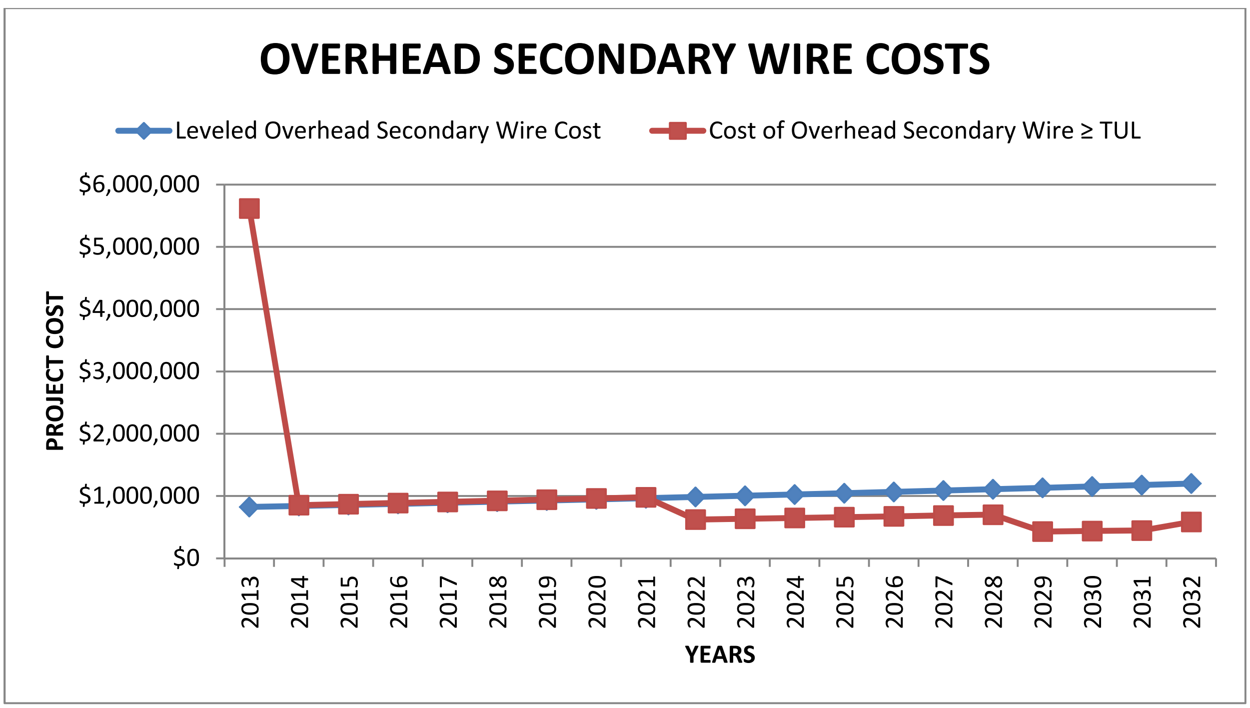


Figure 47

Underground Secondary Cable

Asset Evaluation

Underground secondary cables form a large asset base. Year of manufacture ranges from 1969 to 2012 with the average age being 17 years old. OHEDI uses a Typical Useful Life (TUL) of 35 years. Based upon this timeframe, currently 58km of underground secondary cables have exceeded the TUL of 35 years. OHEDI has chosen a run-to-failure strategy for underground secondary cable, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of underground secondary cables that will exceed this TUL within the next 20 years.

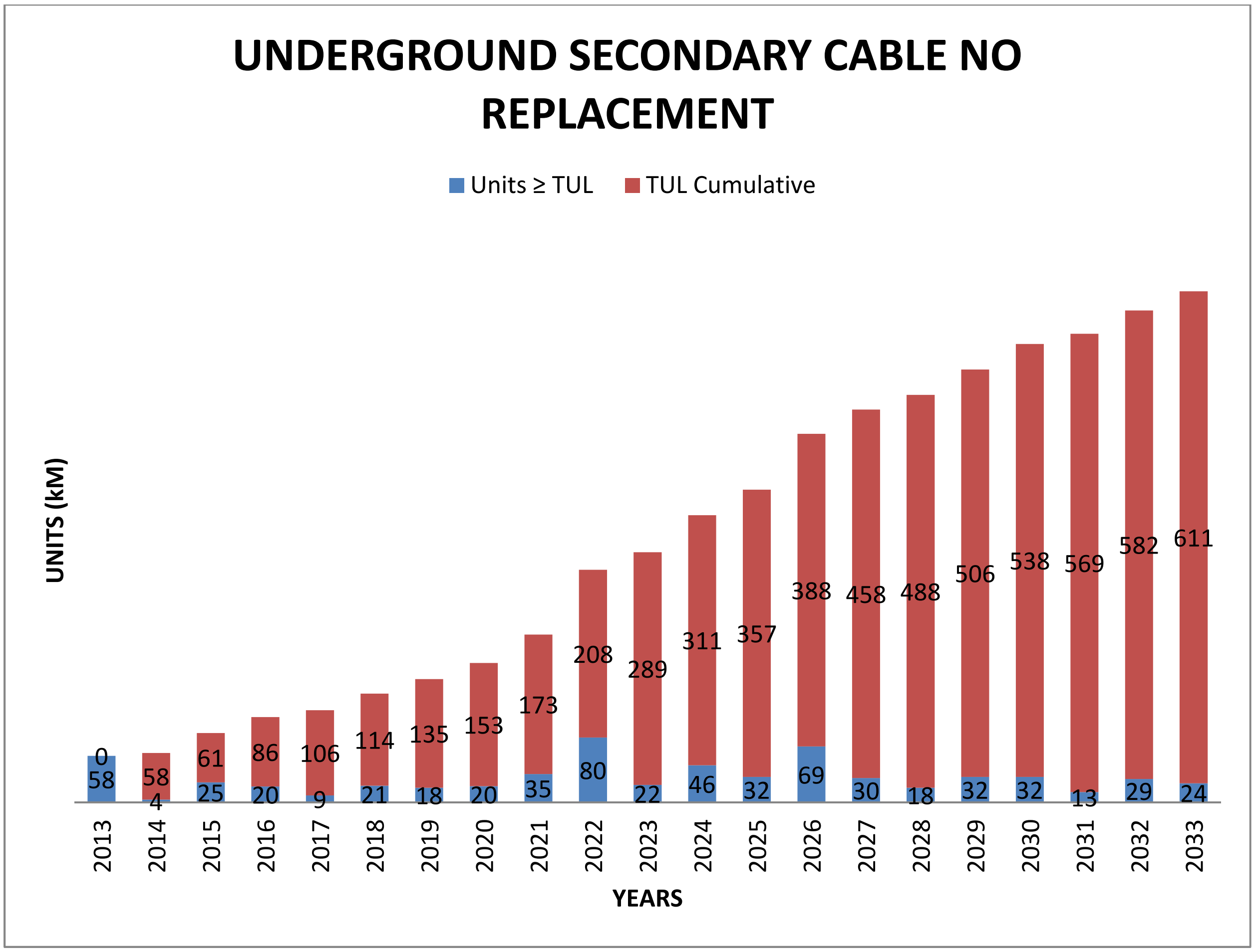


Figure 48

Investment Optimization

Any non-standard underground secondary cables will be replaced with standard cables where possible to lower material costs and decrease spare inventory requirements. Areas with existing direct buried cables will have new ducts installed complete with new secondary cables. The installation of these ducts will allow for easier replacement for future rebuilds.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 21km of underground secondary cable per year until 2018 and one additional km per year thereafter.

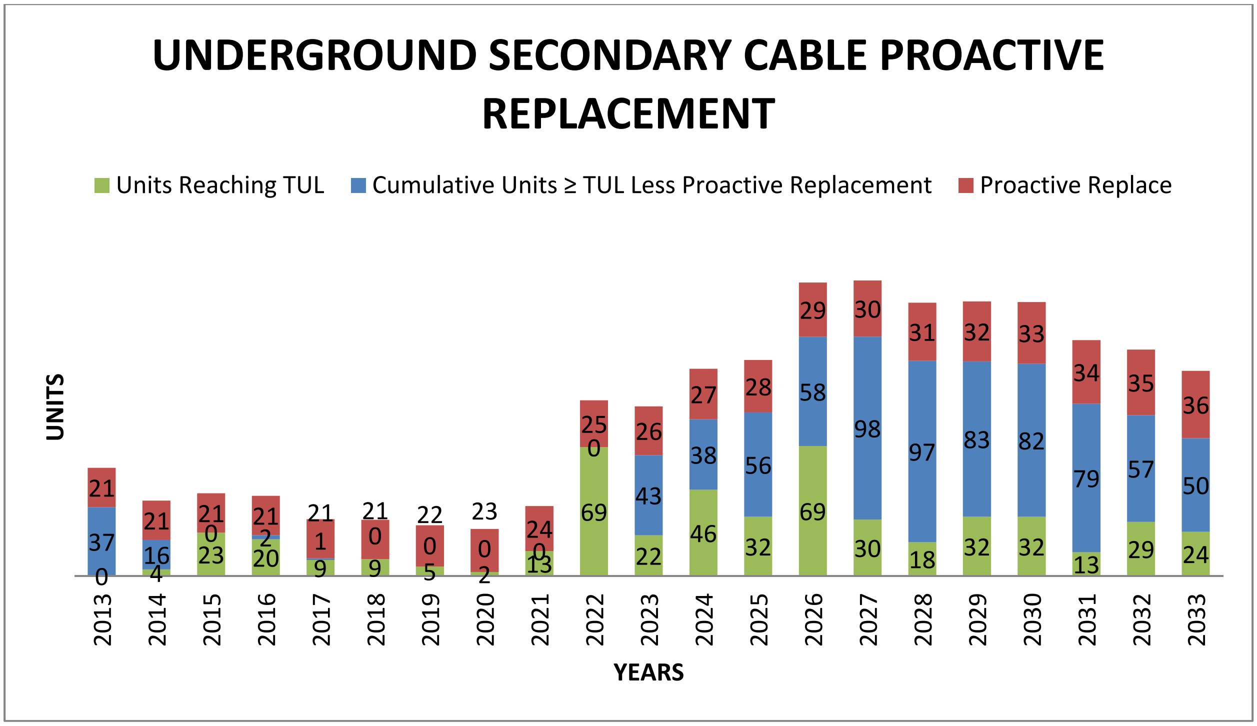


Figure 49

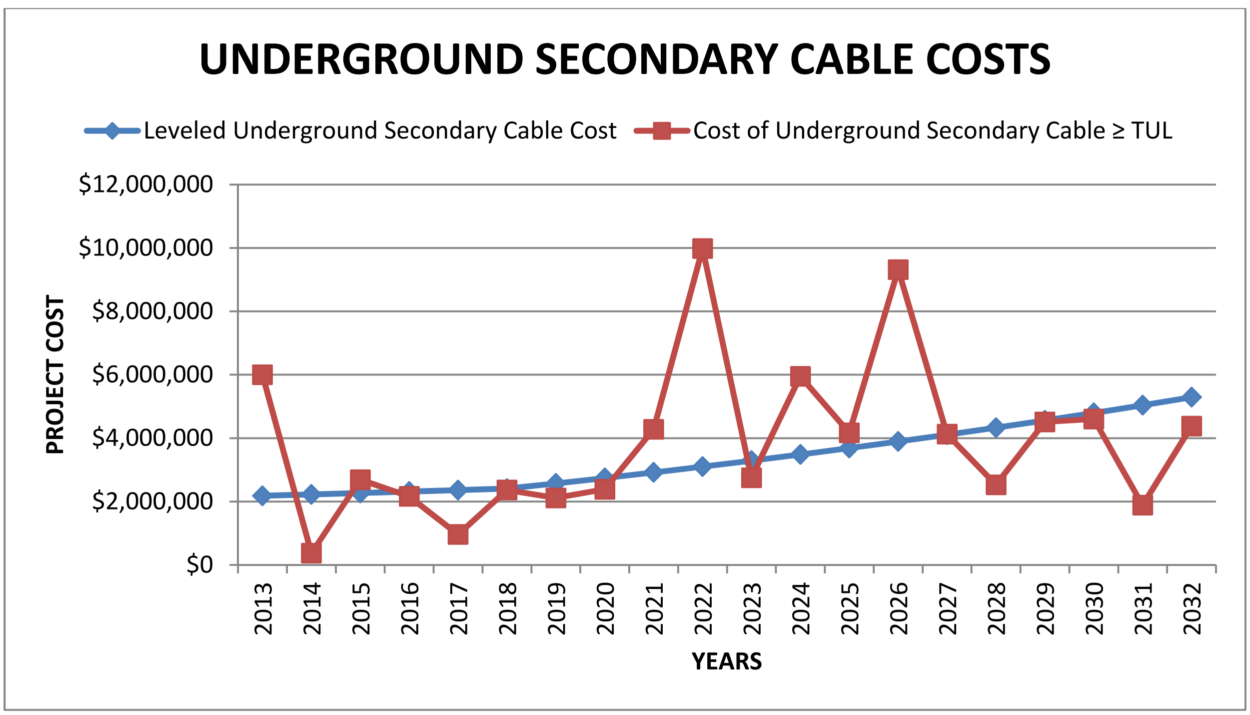


Figure 50

Residential Meters

Asset Evaluation

Residential Meters form a large asset base. In 2011 OHEDI completed a full conversion of all residential meters to next generation AMI meters. Year of manufacture ranges from 1981 to 2012 with the average age being 2 years old. OHEDI uses a Typical Useful Life (TUL) of 15 years. Based upon this timeframe, currently 111 residential meters have exceeded the TUL of 15 years.

The following bar graph shows the quantity of residential meters that will exceed this TUL within the next 20 years.

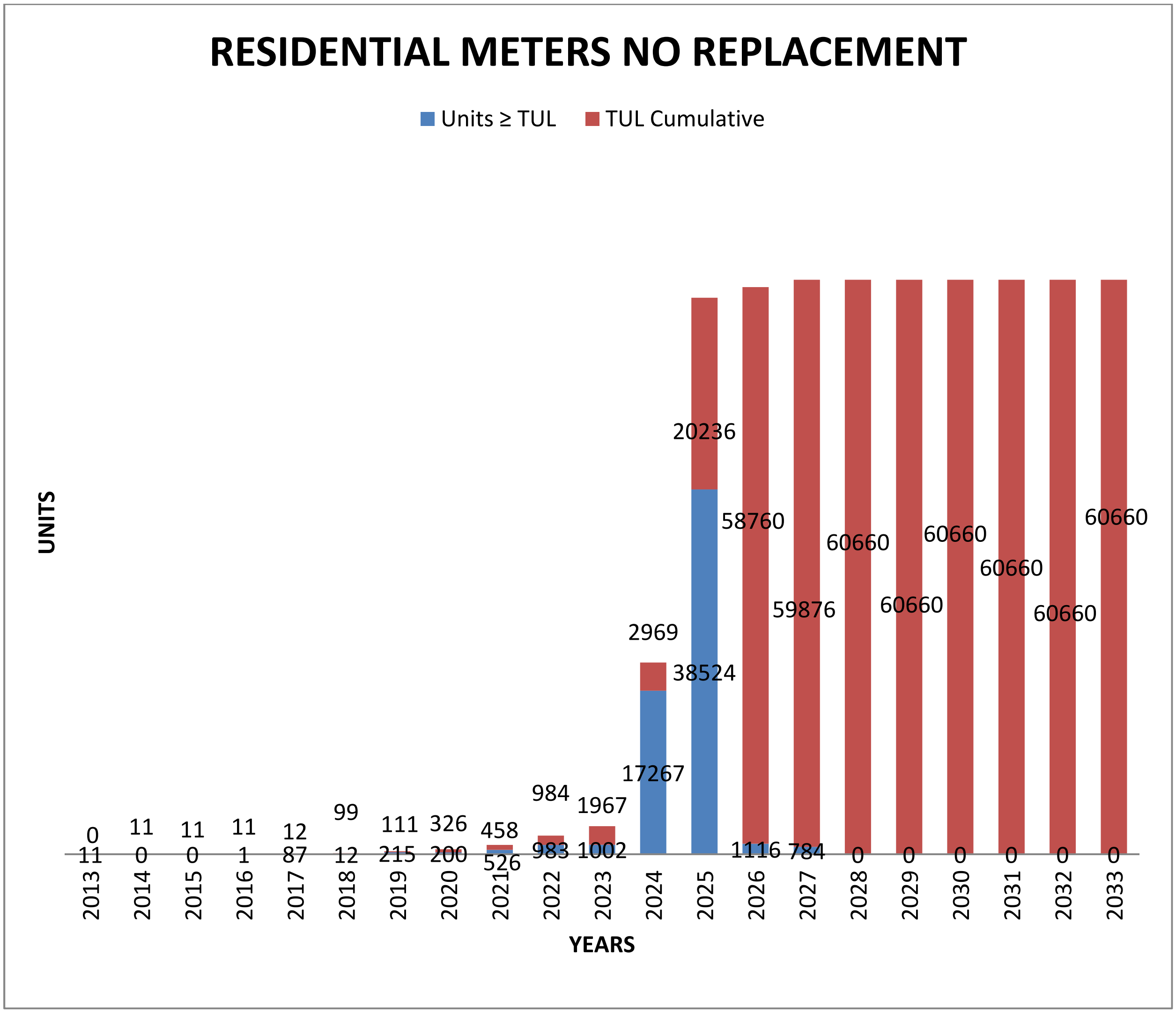


Figure 51

Investment Optimization

Any non-standard residential meters will be replaced with meters where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs, OHEDI forecasts the requirement to replace an increasing amount of residential meters per year until 2027, at which time replacements will remain at a constant level. Replacements will be driven by the sealing/re-certification plan as detailed in the Maintenance Expenditure Plan

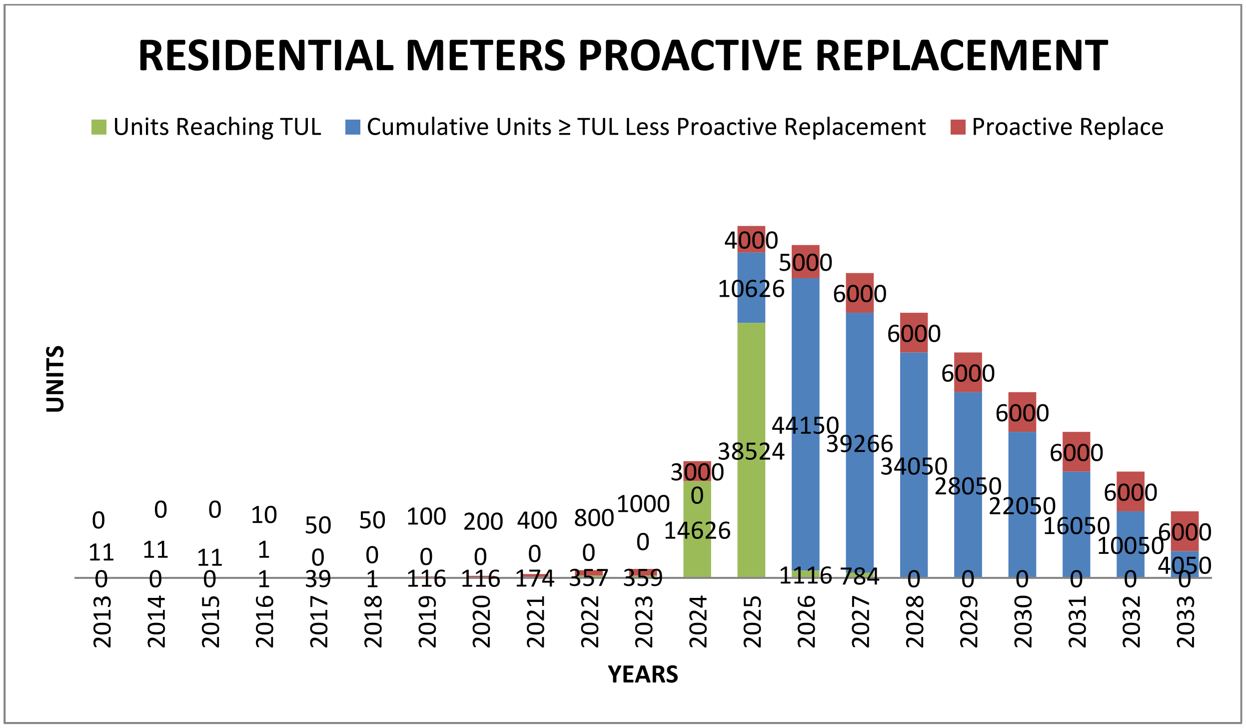


Figure 52

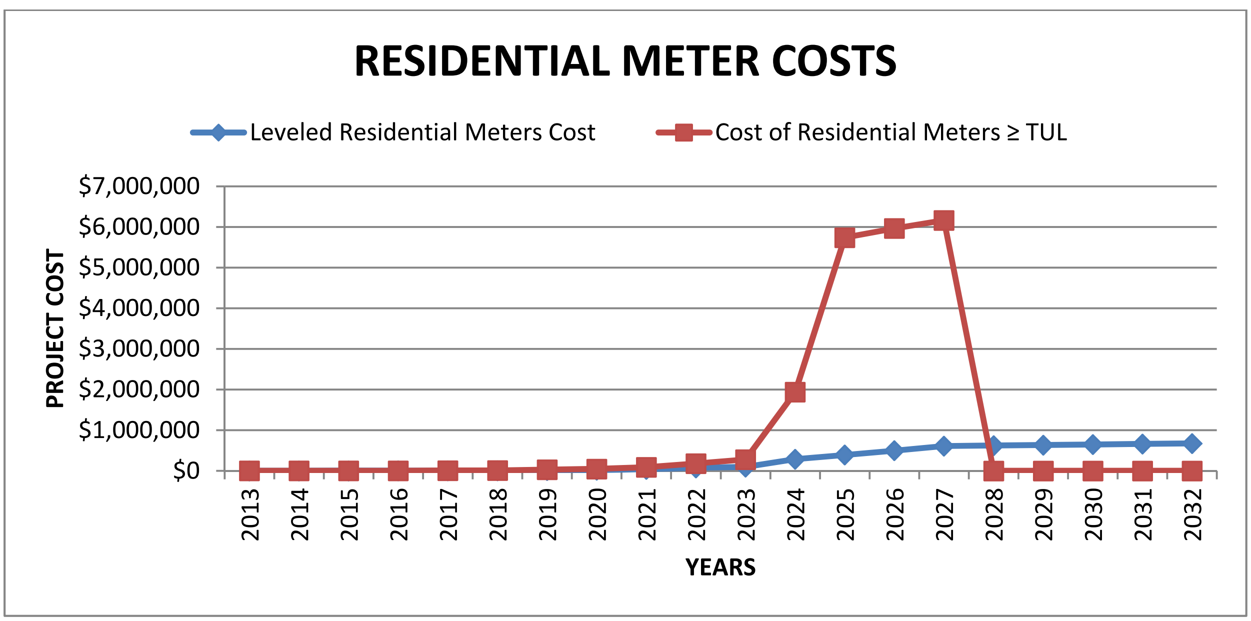


Figure 53

Commercial Meters

Asset Evaluation

Commercial meters form a small asset base. Year of manufacture ranges from 1982 to 2012 with the average age being 10 years old. OHEDI uses a Typical Useful Life (TUL) of 25 years. Based upon this timeframe, currently 20 commercial meters have exceeded the TUL of 25 years.

The following bar graph shows the quantity of commercial meters that will exceed this TUL within the next 20 years.

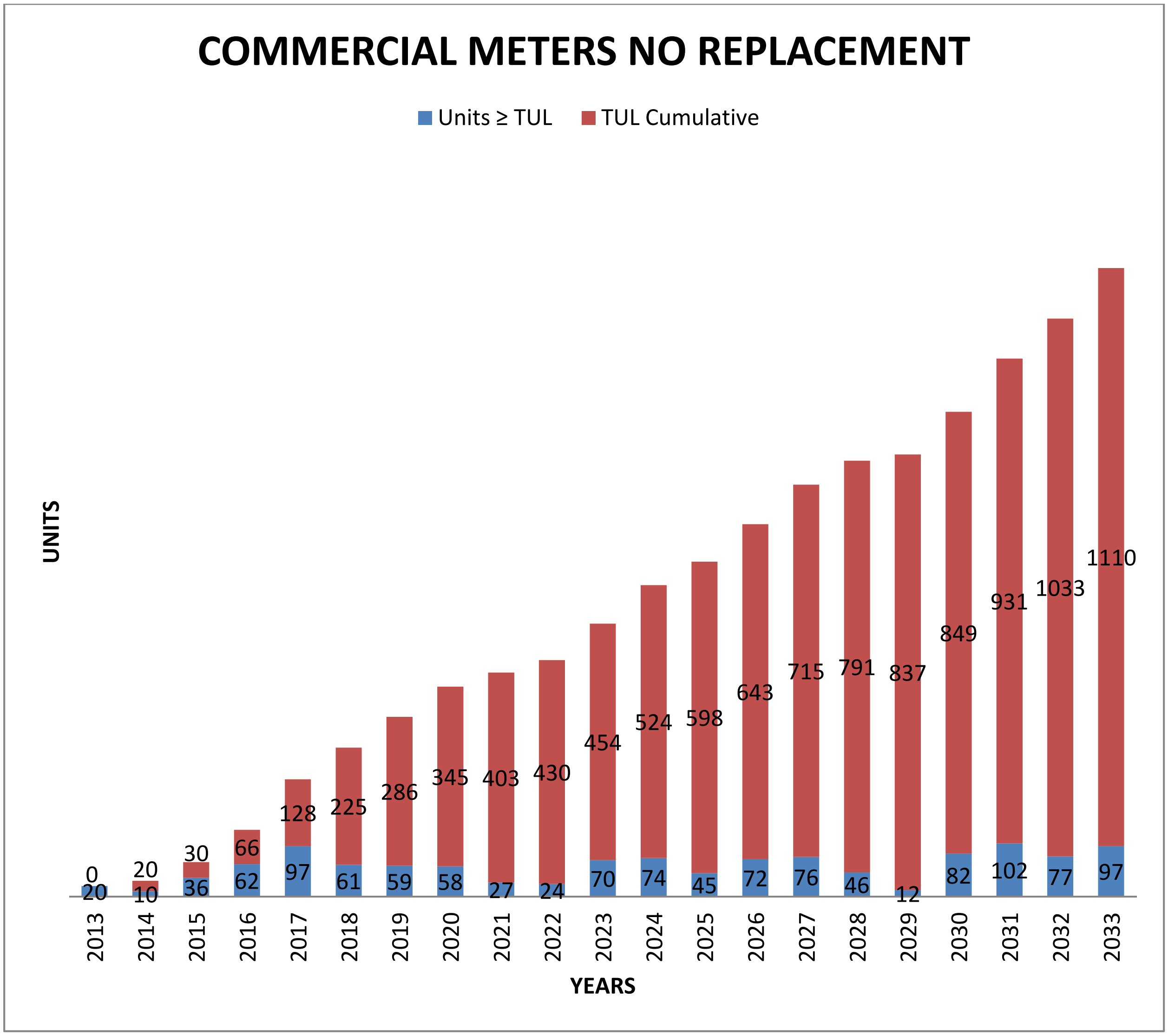


Figure 54

Investment Optimization

Any non-standard commercial meters will be replaced with meters where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace 10 in 2014, an additional 10 per year until 2019, 60 per year until 2026, and 70 per year thereafter.

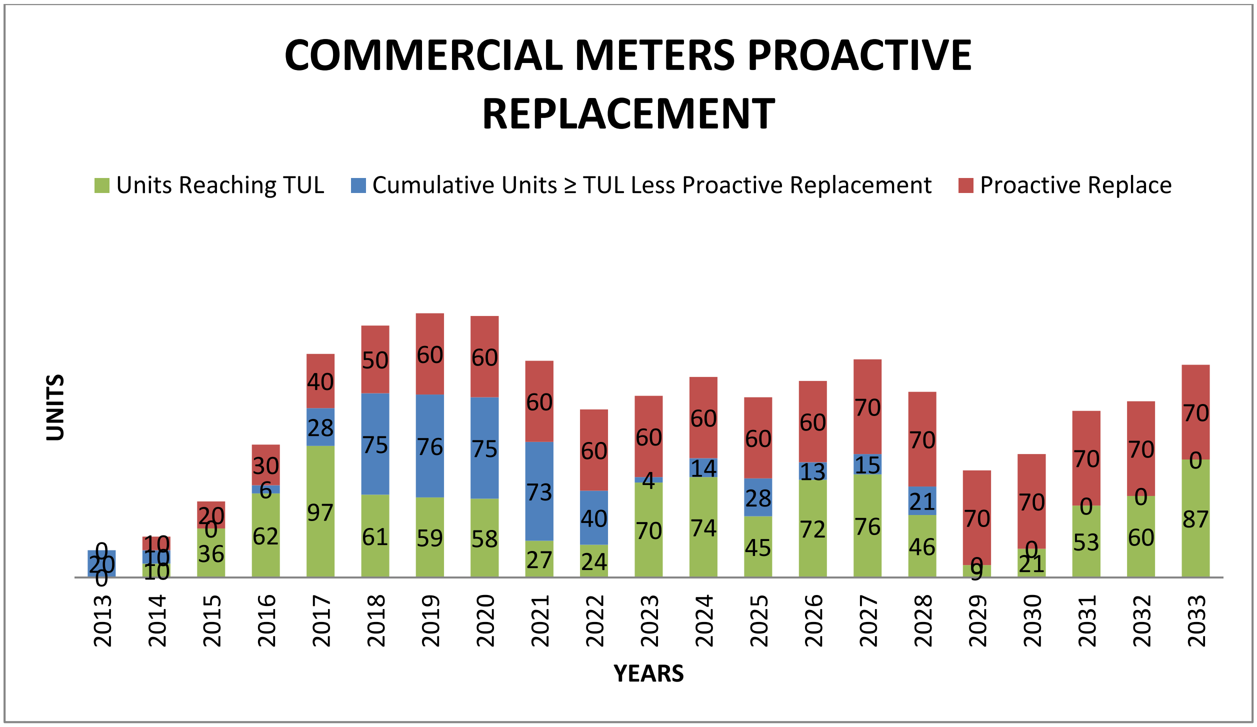


Figure 55

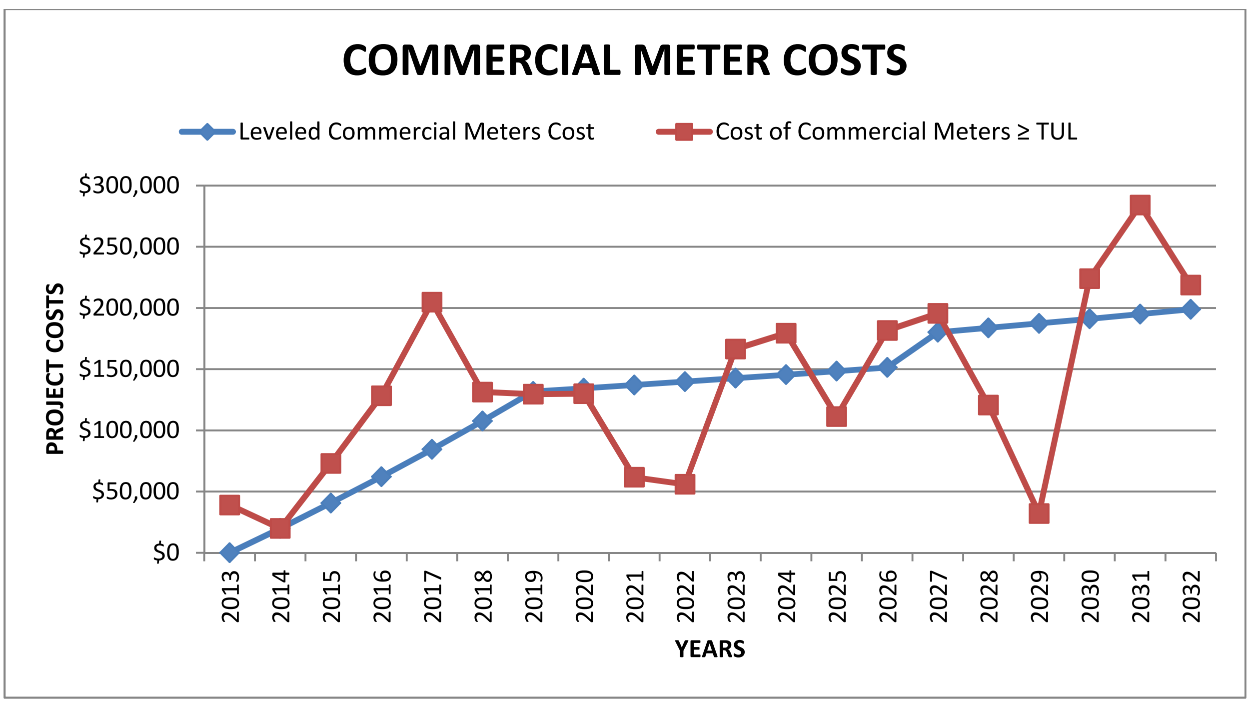


Figure 56

Primary Meters

Asset Evaluation

Primary meters form a small asset base. Year of manufacture ranges from 1970 to 2012 with the average age being 20 years old. OHEDI uses a Typical Useful Life (TUL) of 25 years. Based upon this timeframe, currently 15 primary meters have exceeded the TUL of 25 years. OHEDI has chosen a run-to-failure strategy for primary meters, and will replace upon failure, or ten years after the TUL, whichever comes first.

The following bar graph shows the quantity of primary meters that will exceed this TUL within the next 20 years.

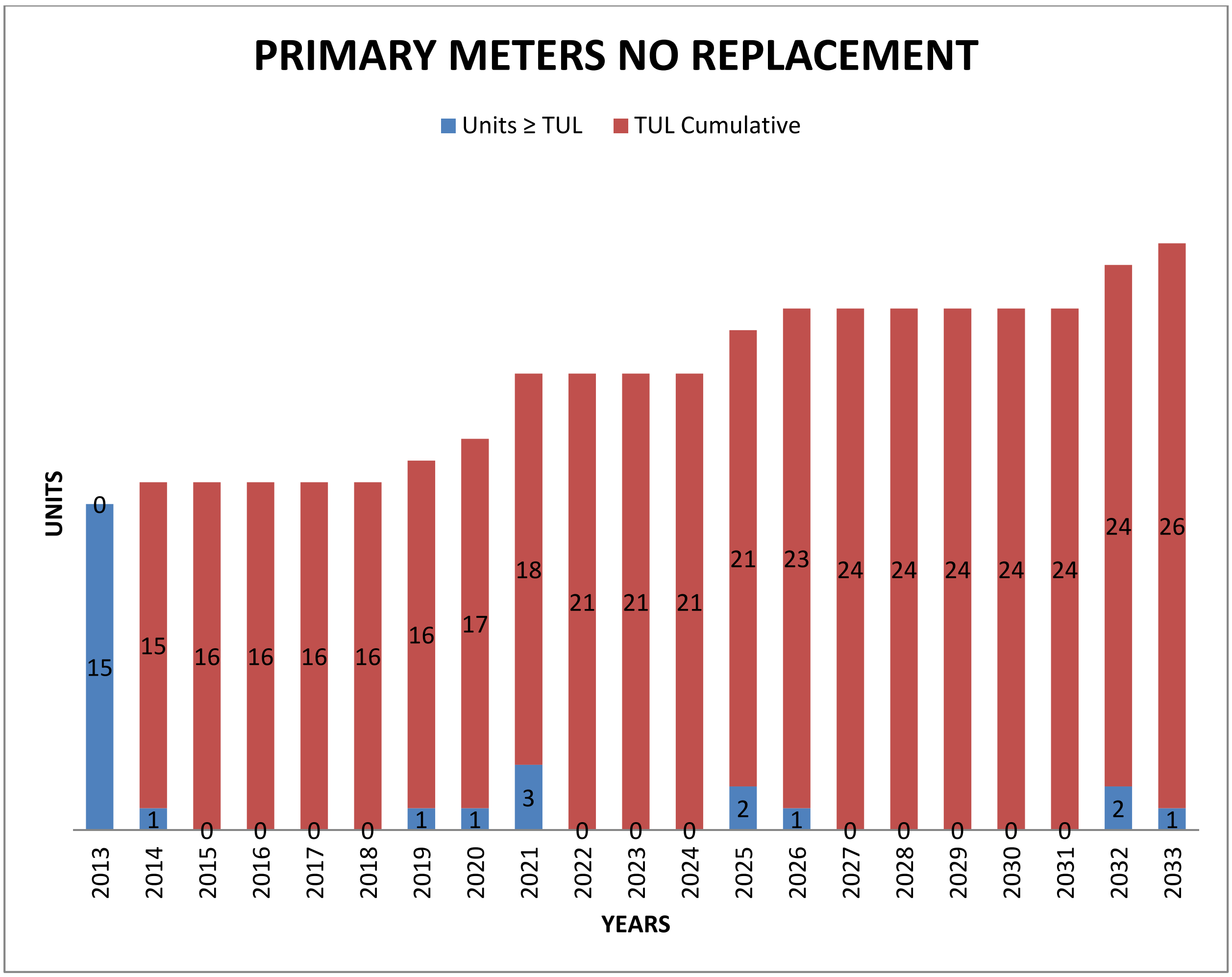


Figure 57

Investment Optimization

Any non-standard primary meters will be replaced with standard primary meters where possible to lower material costs and decrease spare inventory requirements.

20 Year Forecast

In order to level capital replacement costs OHEDI forecasts the requirement to replace two primary meters per year starting in 2015 until 2021, and one per year thereafter.

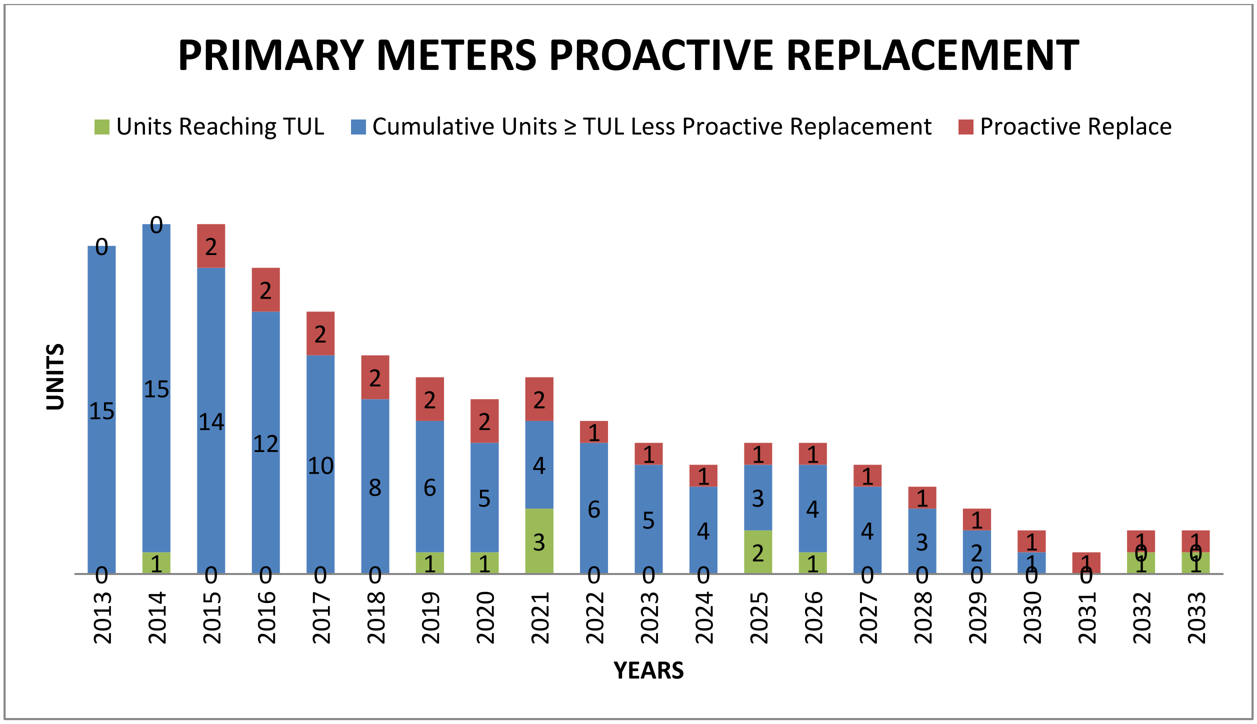


Figure 58

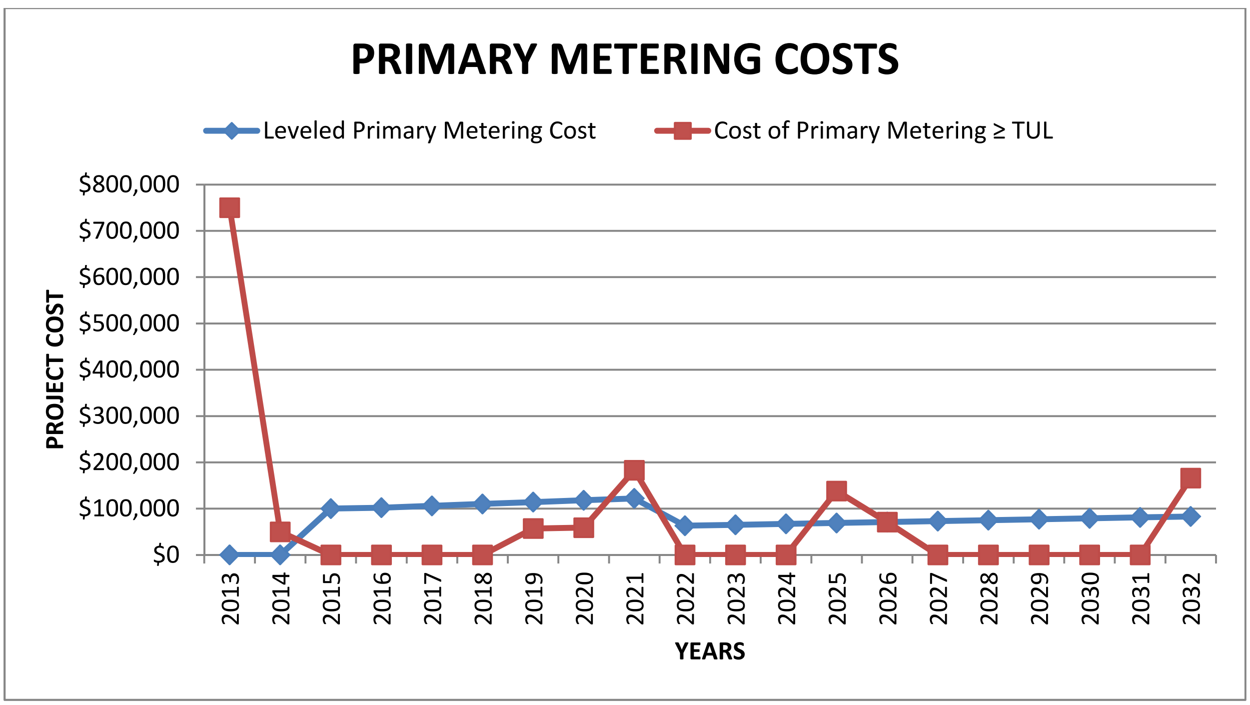


Figure 59

Total Major Distribution Assets

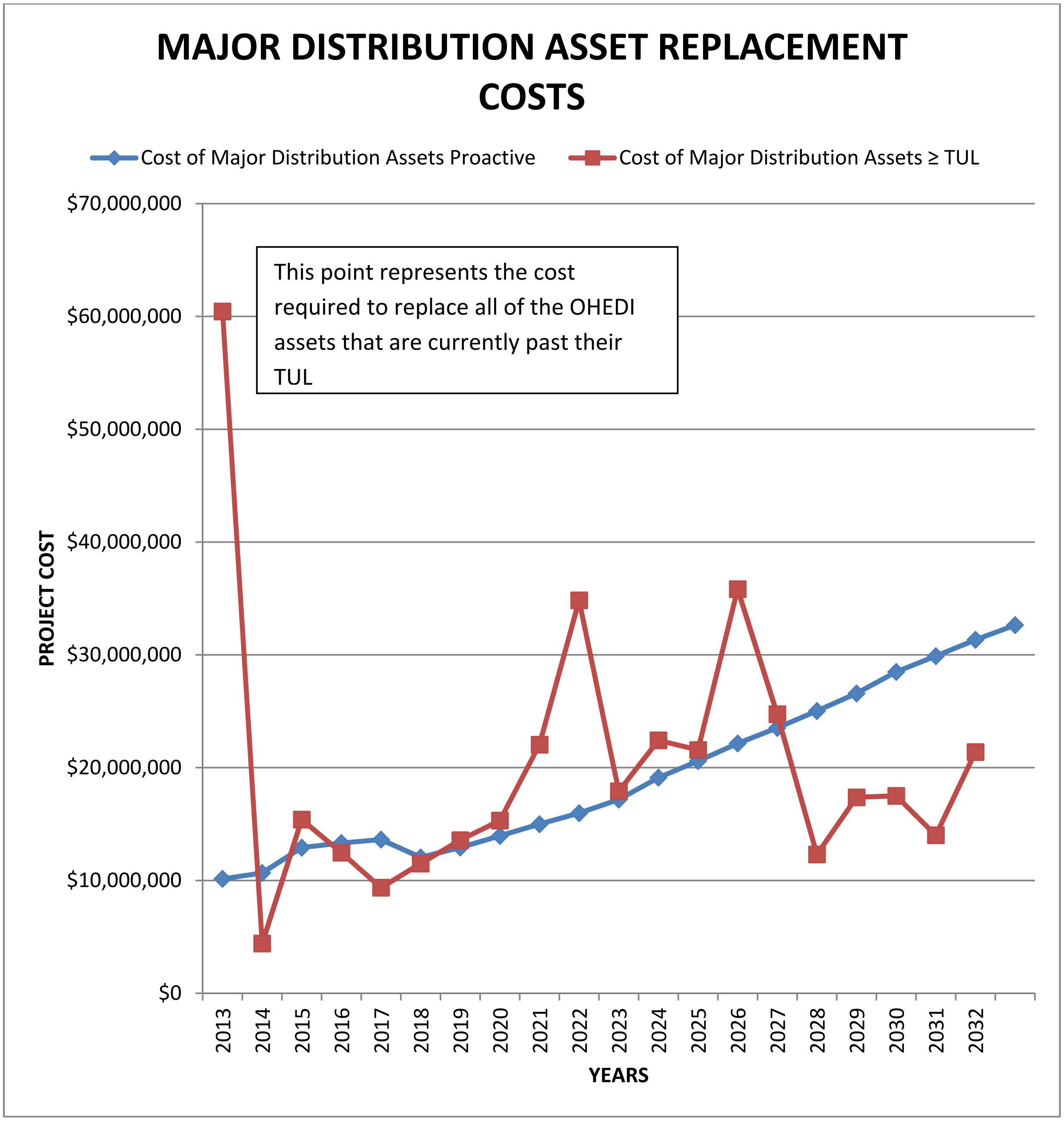


Figure 60

The above graph represents two capital forecasts. The blue, level, line represents a proactive replacement strategy in order to slowly increase capital spending over the next 20 years. The red, jagged, line represents a replacement strategy where most assets are replaced at the end of their typical useful lives, and in the case of an asset categorized as a run to failure asset, the typical useful life plus an additional ten years. To be noted is the large amount of capital required in 2013 in order to replace assets that have already passed their typical useful life.

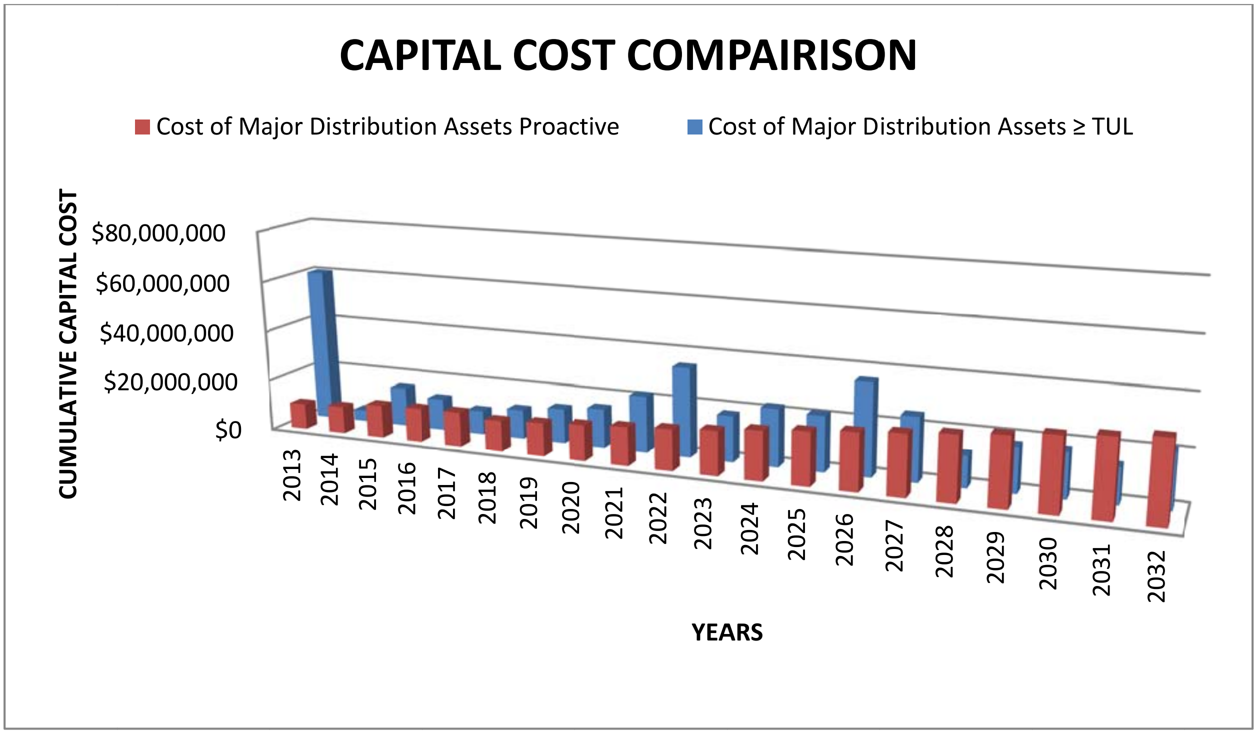


Figure 61

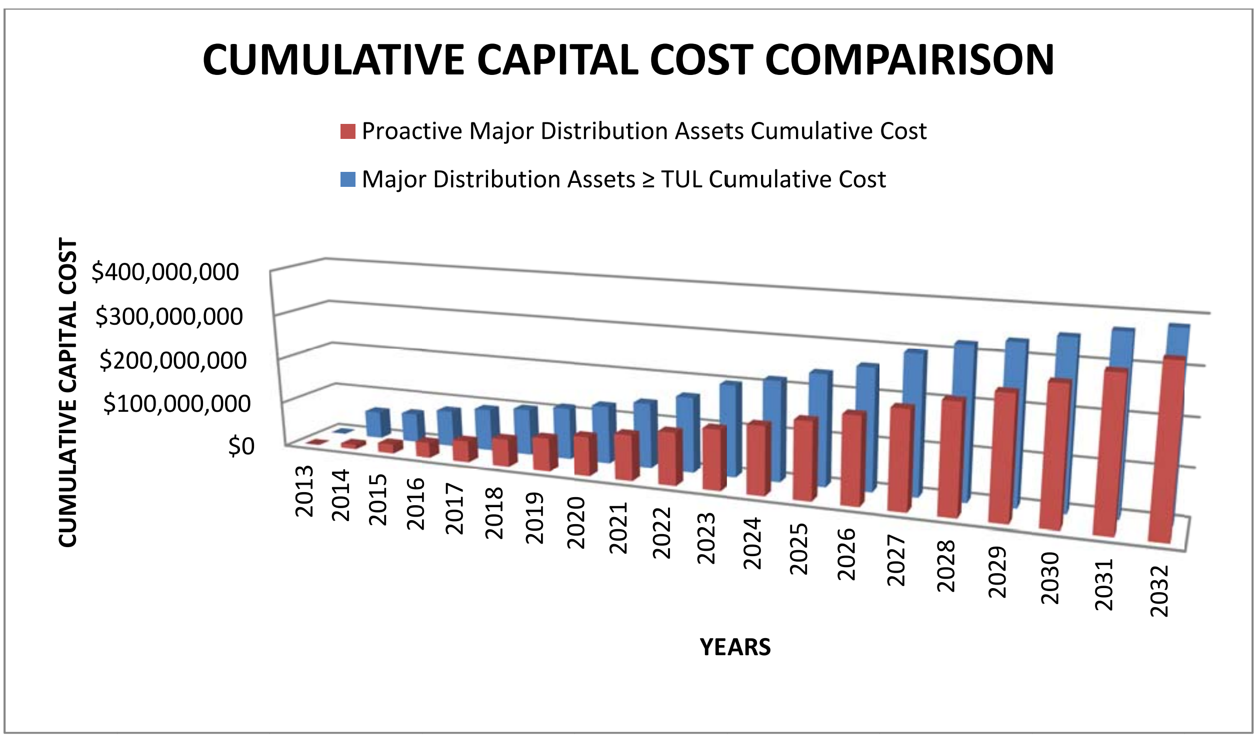


Figure 62

The above graphs represent the two capital forecasts, and the cumulative capital costs required to run both strategies.

Inspection, Condition Assessments, and Health Index

Inspection

The OEB outlines the minimum inspection and interval requirement in the Distribution System Code (DSC). The Town of Oakville is considered an urban area therefore the OEB minimum inspection cycle requirements for all transformers, switches, cables, poles, and civil infrastructure is once every three years. The OEB definition of this requirement is as follows:

"Patrol or simple visual inspections consists of walking, driving or flying by equipment to identify obvious structural problems and hazards such as leaning power poles, damaged equipment enclosures, and vandalism. In cases where a patrol notices that a problem exists or identifies a condition that warrants a more thorough or rigorous inspection, patrol may then include situations where structures are opened as necessary, and individual pieces of equipment carefully observed and their condition noted and recorded. The specifics of these inspections are recorded, and a summary document prepared in the distributor's annual reports as part of their rates or licensing submissions."

OHEDI utilizes a combination of patrols and maintenance activities to complete these inspection requirements, and records information regarding the condition of distribution assets. A minimum of one-third of each major asset is either patrolled or has maintenance performed each year in order to ensure all assets are inspected a minimum of once every three years. During the patrol, minor maintenance or critical items, that may be immediately addressed, are resolved and reported. Major maintenance that requires more complex coordination is subsequently scheduled for completion within the year, or planned for future years.

OHEDI analyzes the feedback from inspection and maintenance routines, as part of condition-based asset assessments. Decisions to replace assets versus proceeding with ongoing maintenance (to extend life), are determined based on a business case assessment.

In addition, OHEDI has a Municipal Transformer Station (MTS) – Glenorchy - connected to the grid, which has specific inspection and maintenance standards identified in the OEB Transmission Code.

Condition Assessments

Conditions of the assets are captured during line patrols and maintenance. In 2011 OHEDI initiated an aggressive and comprehensive 3 year program to review and assess all assets in the system. A total of one-third of all asset conditions were captured at the end of 2011. Two-thirds of all asset condition assessments will be captured by the end of 2012, with the remaining asset conditions to be identified in 2013.

Asset Condition Assessment (ACA) and Risk Assessment (RA) methodologies are used by utilities to develop a Capital Replacement Plan based on both asset condition and criticality. This approach represents a cornerstone of leading Asset Management practices and produces consistent and defensible results that allow for optimal long-term planning, more effective investment practices, and transparent decision making.

Each year ACA information will be collected from assets and calculations are performed in order to generate asset health index.

Health Index

OHEDI has contracted Kinectrics Inc (Kinectrics), a leading provider of asset management services in North America, to recommend Health Index formulations and Condition Criteria for selected distribution asset categories, as well as describe Risk Assessment and Capital Replacement Planning approaches.

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Heath Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

By the end of 2013, we expect to have placed all paper condition assessments into an electronic format which will allow us to perform Health Index calculations. This will allow us to begin to develop a condition based Capital Replacement Plan based on condition distribution and criticality of assets. It will produce consistent and defensible results that will allow for optimal long-term planning, more effective investment practices, and transparent decision making.

Asset Management Systems

OHEDI has a number of identified system initiatives which will provide enhancements to allow more scientific and fact based evaluation of our distribution system. These include:

- GIS System
- Asset Management Data Model and Computerized Maintenance Management System (CMMS)
- Business Excellence Program
- SCADA and Outage Management System (OMS)
- Mobile Business Enablement (eMobile)

The current equipment maintenance and management activities co-ordinated by the Asset Management group at OHEDI are done manually. Optimization of this process requires a CMMS (Computerized Maintenance Management System). The purpose of a CMMS is to bring value-added service to a maintenance/asset management department and to a company as a whole. CMMS is the foundation platform for effective and comprehensive asset management.

Preliminary research was conducted with various vendors to determine what capabilities a CMMS would have and how it would provide a value-added service to OHEDI.

CMMS adds value by automating and providing increased sophistication as follows:

- Moves us towards a condition based maintenance plan that focuses investments in the right areas to achieve optimal value
- Cost Management for equipment and labour, with tracking ability.
- Minimized maintenance and patrol labour and equipment costs (vehicles), with automatic scheduling and the ability for powerline technicians to complete patrols and maintenance on assets in the area where they are already working.
- Reduced duplication of data via links to other enterprise programs and databases.
- Advanced data analysis capabilities
- Asset history
- Optimized asset reinvestment using asset history tracking. Issues with an asset can be caught and resolved before the asset fails, mitigating safety concerns, system outages, or secondary damage to Oakville Hydro distribution system.

Maximo (by IBM) has been selected and is being implemented to satisfy the CMMS requirements. Along with the above mentioned values, it also allows provides the following additional functionality:

- Paperless documentation of condition assessments by means of mobile deployment to field crews
- Automatic Health Index calculations to determine the remaining health of assets based upon the collected condition information by field crews
  - Health Index can be used to prioritize investments based upon the condition of assets in the system
  - Health Index can be used in order to obtain an overall picture of the health of all system assets, or health of a certain class of asset
- Failure tracking of assets in order to build a repository of past failures and failure modes.

Procurement Efficiency

OHEDI employs a number of cost effective solutions to ensure procurement efficiency once the need for asset replacement has been established. Each major distribution asset listed above includes investment optimization information in order to ensure efficiency.

As part of the asset replacement decision process, OHEDI is reviewing the standardization of equipment for replacement. The standardization will allow for minimized inventory holdings, as fewer types of equipment are required to be kept in spare inventory for emergency replacement purposes. The standardization will also provide the ability to purchase more equipment in bulk, possibly decreasing overall material costs and allowing for long-term relationships with suppliers.

Over time, the implementation of this strategy into the Asset Management Plan will allow for forecasting of equipment requirements, which will allow for establishment of additional long-term relationships with suppliers and provide us an outlook of the required capital expenditures on materials over a yearly time frame.

Publicly Available Specification (PAS) 55

OHEDI has obtained and reviewed PAS 55-1:2008 and PAS 55-2:2008 to help implement the asset management policy, strategy, objectives and plans. Although OHEDI does not have any current plans to certify its Asset Management System in accordance with PAS 55, it is prudent to ensure that the approach does align with industry frameworks for asset management.

Summary

This document provides sufficient information, guidance and direction for the development and ongoing management of the Capital Expenditure Plan and Maintenance Expenditure Plan, separate documents which contain the detailed plans to achieve the outcomes of the Asset Management Objectives. It will be communicated to all relevant stakeholders, and will be reviewed regularly to ensure currency, consistency and effectiveness.

2013

Oakville Hydro Electricity Distribution Inc.

Maintenance Expenditure Plan

12/07/2013

Version 1A

Table of Contents

1 Maintenance Expenditure Plan Purpose and Objective

The purpose of the Maintenance Expenditure Plan (MEP) is to provide a description of maintenance planning criteria and assumptions. It also describes routine and preventative inspection and maintenance policies, practices and programmes. This document will be reviewed and updated on a yearly basis.

2 Inspections and Patrols

2.1 Due Diligence Inspections - Municipal Substations

Each year the ESA conducts a Due Diligence Inspections (DDIs) of the Municipal Substations. Due Diligence Inspections are inspections of LDC electrical distribution installations and are performed by ESA Inspectors. DDIs were created in order for ESA to carry out its due diligence with respect to regulating to O. Reg. 22/04. These inspections are complimentary to the Auditor reports, the Declaration of Compliance, Serious Incident Reports and any Public Safety Concerns. When combined, these compliance measures provide ESA with appropriate information to adequately assess compliance with O. Reg. 22/04. DDIs provide a means of assessing whether LDCs are following their safety regulatory obligations at the site of the installation.

<u>Scope:</u> ESA Inspector's schedule visits with the LDCs to review a sample set of new construction, maintenance, repair, temporary services and/or replacement work of electrical equipment owned by the LDC or attachments by a 3rd party to the LDC's asset (ie. pole). Construction consists of Underground, Overhead or Substation sites. Inspectors are given comprehensive guides (developed by the Utility Regulations Department), and Plans or Work Instructions (created by the LDC) to follow.

<u>Inspection Process:</u> The Inspectors schedule DDI appointments with the LDCs and while onsite Inspectors observe and record adherence to the Plans, Work Instructions and construction verification procedures. The Inspector acts as an observer and documents the observations in comprehensive guides. If the construction does not match the Plan or Work Instruction supplied to the Inspector they will make note of the differences and whether the installation change has been recorded. Any additional safety concerns or hazards an Inspector notes are also included in the guides. Any installations deemed, by the Inspector, to be an imminent fire, shock or explosion hazard the Inspector is to ensure the site is made safe before leaving the site.

<u>Reporting:</u> The ESA Inspector submits the guides to the Utility Regulations Department which in turn assesses the information based on O. Reg. 22/04 and discusses the findings with the LDCs. Utility Regulations produces a report documenting the findings and reviews the LDC action plan and follows up with the LDC for the parts of the installation or processes where the LDC was not in compliance with O. Reg. 22/04. The report also confirms those installations that are in compliance

2.2 Protection & Control Inspections - Glenorchy

An extensive inspection of all station equipment both high and low voltage is conducted weekly with any deficiencies reported using the inspection form, and corrective action carried out accordingly. Testing includes the following activities:

1. Locate the ground grid at the station (rods, conductors, and fence).
2. Check on the bonding from grid to fence and equipment.
3. Perform soil resistivity and gravel assessment.
4. Measure potential gradient across the property.
5. Measure step Potential value for safety.
6. Measure touch Potential value for safety.

7. Measure ground Potential Rise (GPR) value for safety.
8. Zone of Influence (ZOI) value for communication equipment.
9. 2D and 3D model created for simulating different scenarios.
10. Recommendation and findings for the existing ground grid.

2.3 Municipal Stations Patrol

MS's are patrolled on a monthly schedule which involves inspection of the compound, transformers, relays, batteries, insulators/arresters, switches/fuses and terminations/grounds. Any deficiencies are reported using an inspection form, and corrective action is carried out accordingly. .

2.4 CSS Line Inspections

Customer Specific Substations (CSS). CSS's are patrolled by operations crews once per year. They confirm issues and conditions for areas such as: Signs, access, interior, oil temp, winding temp, oil level, oil pressure, leaks, switchgear cabinet, fuses, arresters, switches, terminations, and grounds.

2.5 Operations O/H Switch Patrols

Overhead switching and protective device patrols consisting of at least one-sixth of the installed overhead switches, is completed by operations. Operation provides a visual inspection of the overhead switches and their conditions. They confirm issues and conditions for areas such as: Accessibility, grade, blade/fuse, arrester, brackets, connections, grounding, identification, terminations, cable guards, check and record ground resistance, perform an infrared scan, and note presence of fault indicators. They also confirm if the switch is shown correctly on the grid maps with the correct address and information shown on the switch sheets.

Overhead conductor patrols are completed each year. Two different scanning methods are used. The first method is an infrared scan of overhead conductors to identify any heat issues that may be present due to poor connections or failing equipment. The second method employs a radio frequency scan of the streets the overhead conductors are on to identify any issues that may not be picked up by the infrared scanning. A minimum of one-third of the overhead lines will be scanned each year to identify issues that may be present.

2.6 O/H Tx Patrol

Overhead distribution transformer patrols consisting of at least one-sixth of the installed overhead transformers, is completed by operations. Operation provides a close up visual inspection of the overhead distribution transformers and their conditions using bucket trucks. They confirm issues and conditions for areas such as: Accessibility, grade, tank, paint, cutout, arrester, brackets, bushings, connections, grounding, identification, and check for oil leaks. They also confirm if the transformer is shown correctly on the grid maps with the correct address and information shown on the existing transformer spec sheets. The second section, consisting of the other one-sixth of the installed pole mounted transformers, is maintained by operations crews. Along with this review they also check and record secondary voltage levels, confirm ground resistance, ensure the phase connection matches that shown on the grids, perform an infrared scan, and note any additional issues.

2.7 U/G Line Patrols

Switches installed in vault structures are patrolled by operations crews every three years. Due to the limited number of these style switches it is not feasible to split the patrols into separate years. They confirm issues and conditions for areas such as: tank, paint, elbows, fault indicators, motor operators, foundation, identification, grounding, RTU, and AC service. Along with this review they also check and record ground resistance, perform an infrared scan, and note any additional issues. Pad mounted switching and protective device patrols consist of at least one-sixth of the installed pad mounted switches, is completed by operations crews. The operations crews will open up the enclosure and confirm issues and conditions for areas such as: Obstructions, grade, accessibility, security, tank, paint, current sensors, terminations, housekeeping, motor operator, fault indicator, foundation, identification, insulators, grounding, AC service, and sump pump. Along with this review they also check and record ground resistance, perform an infrared scan, and note any additional issues.

2.8 U/G Cable Testing

The primary goal of any preventive maintenance plan for Medium Voltage (MV) power cables is to test and analyze the overall insulation of the cable as well as to determine the serviceability of the accessories through data trending to prevent catastrophic failures. Testing technologies being considered are DC hi-potential testing, AC hi-potential testing, very low-frequency (VLF) testing, power factor/dissipation factor testing, VLF dissipation factor testing, off-line partial discharge testing, and online partial discharge testing.

2.9 U/G Pad Tx Patrol

Padmount distribution transformer patrols consisting of at least one-sixth of the installed padmount transformers, is completed by operations. Operation provides an interior and exterior visual inspection, of the pad mounted distribution transformers and their conditions. They confirm issues and conditions for areas such as: Accessibility, grade, obstructions, security, tank, paint, foundation, bollards, identification, and check for oil leaks. They also confirm if the transformer is shown correctly on the grid maps with the correct address and information shown on the existing transformer spec sheets. Along with this review they also check and record secondary voltage levels, confirm ground resistance, ensure the phase connection matches that shown on the grids, review and record elbow, insert, arrester and cable tag conditions, perform an infrared scan, and note any additional issues.

2.10 U/G Tx Patrol

Submersible distribution transformer patrols consisting of at least one-sixth of the installed submersible transformers, is completed by operations. The operations crews will open the submersible enclosures and confirm issues and conditions for areas such as: Accessibility, grade, obstructions, location, security, grounding, lid, vault, tank, inserts, bushings, elbows, connections, and they check and record information on ground wire resistance, types of fuses used in the transformers, amount of oil, weight, secondary voltages, and if there are any heat issues found. .

Vault distribution transformer patrols consisting of at least one-third of the installed vault transformers, is completed by operations. Operations crews will enter the vault rooms and confirm issues and conditions for areas such as: Accessibility, obstructions, security, signage, tank, transformer type, bushings, elbows, inserts, junctions, fuses, grounding, LV electrical, and they check and record information on ground wire resistance, amount of oil in the transformers, the weight of the transformers, secondary voltages, housekeeping issues, and if there are any heat issues found.

Padmount distribution transformer patrols consisting of at least one-sixth of the installed padmount transformers, is completed by a contractor. The contractor provides an exterior visual inspection, of the pad mounted distribution transformers and their conditions. They confirm issues and conditions for areas such as: Accessibility, grade, obstructions, security, tank, paint, foundation, bollards, identification, and check for oil leaks. They also confirm if the transformer is shown correctly on the grid maps with the correct address and information shown on the existing transformer spec sheets.

2.11 Meter Maintenance

This covers the cost for meter expenses. Measurement Canada regulations require that all meters be calibrated and sealed prior to being used to for revenue metering. Meters are assigned different seal periods based on type and manufacture. Typically, commercial meters have a 6 year seal period and residential meters have 10 years. This can vary dependent on performance level of meters over time. If accuracy of meters decreases, meters can have their seal period reduced by Measurement Canada. When residential meter seals expire a sample group of the meters is re-verified by an accredited meter service organization. Based on the results of the testing, the complete lot of meters installed in the field can have their seal periods extended for a specific number of years at which time sample testing reoccurs. Eventually all meter must be removed for testing. If a sample group of meters fails re-verification then the total population of meters in the lot must be removed for recalibration. Measurement Canada has introduced a new regulation which requires interim sample testing of residential smart meters 5 years in advance of their seal expiry. This regulation is meant to provide increased monitoring of new smart meters that do not have a performance history.

2.12 Cable Failure Testing

When primary cables fail they are sent to a third party laboratory to investigate the root cause of the failure, receive comment on the aging of the cables, and have suggestions provided regarding future inspection/diagnostics for similar cables under operation. Testing and analysis will include, but will not be limited to:

- autopsy of the cable including jacket, semicon, and insulator
- measurement of dimensions and comparison with the standard recommendations
- microscopic analysis of insulation samples to observe water tree, void and contamination
- investigation of the failure mode and probable cause of the failure

A report will be issued to OHEDI with the results of the above work.

3 Asset Maintenance

3.1 Maintenance of Transformer Station Equipment

Yearly maintenance will include visual inspection, infrared survey, insulator washing, transformer fluid analysis, and the complete maintenance of power systems connected to circuit (T36B & T37B) every alternative year.

Equipment and tests include:

- 230kV Disconnect Switch – Visual inspection, operational verification, contact resistance in micro-ohms, and insulation resistance in mega-ohms.
- 230kV Surge/Lightning Arrestors – Visual inspection, counter check, and insulation resistance in mega-ohms.
- 230kV / 28kV Transformers – Visual inspection, ratio test, capacitance and dissipation factor test, insulation resistance of all windings in mega-ohms, auxiliary device confirmation, and sampling & analysis of main tank fluid & TLTC for:
    - 5-Part oil screen (ASTM D-877)
    - Moisture content
    - Dissolved gas-in-oil analysis
- 28kV Surge/Lightning Arrestors – Visual inspection, counter check, insulation resistance in mega-ohms
- 28kV Siemens GIS – Visual inspection, operational verification, verify gas pressure levels
- Structure Components Misc. (Lightning arresters, potential transformers, etc.) Substation Yard – Visual inspection, insulation resistance in mega-ohms, ground grid resistance test
- Automatic transfer switches – Visual inspection and operational test
- Batteries & charger – Visual inspection, battery cell voltage measurement, battery cell link resistance measurement, battery cell impedance measurement, charger output level confirmation
- Insulator Washing – Water washing of all exposed 34.5/69/230kV apparatus (where accessible for truck)
- Relays T60(HV), SEL487E (HV), D60(HV), D60(LV), C60(LV) – Visual inspection, confirmation of relay settings, calibration test, and functional test.

3.2 Maintenance of Distribution Station Equipment

Batteries are subjected to a shallow drain once every two months to check capacity. Battery problems and hazards are remedied as found, if possible, and larger repairs are reported and scheduled accordingly. If the batteries need to be taken out of service immediately a spare set of batteries with a charger are put into place.

Transformer oil testing is completed by a third party on an annual basis. Results are trended and analysed to identify potential transformer problems or requirements for transformer replacement. A report is issued to OHEDI that includes the test results, recommendations for follow up testing, and any general transformer deficiencies that were noted during the course of the oil sampling.

An extensive two to three week outage is required every three years to perform maintenance on both high and low voltage systems. During substation maintenance, problems and hazards are remedied before the equipment is put back in service. Specific tasks include visual inspection, shutdown tests, electrical integrity tests, station service transformer reports and secondary switchgear reports. Maintenance for rackable substation breakers involves removing them from service and conducting a visual inspection, mechanical testing, and a timing test. Problems and hazards are remedied as found if possible, and larger repairs requiring assistance from the manufacturer are scheduled and remedied before putting the breaker back into service. The protection relays are tested and calibrated during the time that the associated breaker is out of service. Test results are recorded for equipment 'as found' prior to maintenance in addition to the results 'as left' after completing all maintenance tasks. Outsourcing of the full station maintenance to a third party contractor is performed as required to meet all of the distribution station maintenance targets.

3.3 Maintenance of Poles, Towers and Fixtures

3.3.1 Wood Pole Test/Treat

Wood pole patrols are completed in two sections each year. The first section, consisting of at least one-sixth of the installed wood poles, is patrolled currently by a subcontractor. The subcontractor will visit each pole location and confirm issues and conditions for areas such as: Obstructions, grade, accessibility, rot, cracks, infestations, identification, insulators, feathering, down guys, span guys, mounted equipment, and third party attachments. The second section, consisting of one-sixth of the wood poles, is patrolled by a contracting crew which performs testing and treatments. Along with checking the above noted conditions, they will check the pole above and below ground for rot, voids, and infestations. If any adverse conditions are found, chemical treatments are applied to mitigate further damage to the pole. A list of poles beyond treatment is provided at the end of the patrol, these poles are recommended for replacement. OHEDI has considered performing the wood pole testing every seven years; however, this has been modified to six years in order to coordinate with the three year patrol cycle. This cycle is cost effective because it satisfies both the maintenance and patrol requirements.

3.3.2 Pole Contractor Patrol

Other poles are patrolled by a subcontractor every three years. Due to the limited number of poles in this category it is not feasible to split the patrols into separate years. They confirm issues and conditions for areas such as: Obstructions, grade, accessibility, cracks, rust, crumbling, identification, insulators, down guys, span guys, mounted equipment, and third party attachments.

3.4 Overhead Distribution Lines and Feeders – Right of Way

3.4.1 Tree Trimming

Trees contribute greatly to the natural beauty of the Town. But, if not properly managed, they can create power outages and/or hazardous situations by touching or even falling on the power lines. OHEDI has contracted the Town of Oakville's Urban Forestry Services to conduct regularly scheduled tree maintenance across Oakville.

3.4.1.1 Pruning Cycle

Map made available by Microsoft Streets & Trips

The Town ensures that trees in each of the three zones of the service territory are pruned responsibly on a three-year cycle to ensure safety and maintain the integrity of the natural surroundings. To complete all areas in the allotted time, the Town may need to contract the help of private, specialized tree experts. These private contractors will be pruning trees with the same care and precision as the Town.

3.5 Maintenance of Underground Conduit

3.5.1 U/G Con Maintenance Labour

Civil Infrastructure patrols are completed in two ways. The first section, consisting of civil infrastructure installed with other equipment, is patrolled by crews during the same time as the other equipment patrols. Any adverse conditions found will be noted during the other equipment patrols for the civil infrastructure. The second section, consisting of one-third of the civil infrastructure such as service boxes, vacant transformer vaults, manholes, and secondary pull boxes are patrolled by operations crews every year. Operation crews confirm issues and conditions for areas such as: Obstructions, grade, access, security, lid, grounding, damage, collar, vault, duct entrances, drain, sump pumps, and contents. They will also perform an infrared scan of any installed cables or junctions to identify issues.

3.5.2 Residential Vault Washing

OHEDI classifies submersible distribution transformers into two categories. The first are commercial submersible transformers, which include any transformers installed in densely populated commercial areas of Oakville in large submersible vaults. The second are residential submersible transformers, which include any transformers installed in lightly populated residential areas in Oakville in smaller submersible vaults.

Residential submersible distribution transformers do not require the same level of cleaning that the commercial examples do, as the lids do not allow for the same amount of debris to collect. The patrols of these transformers are completed in two sections each year. The first section, consisting of at least one-sixth of the installed submersible transformers, is patrolled by operations crews. The operations crews will open the submersible enclosures and confirm issues and conditions for areas such as: Accessibility, grade, obstructions, location, security, grounding, lid, vault, tank, inserts, bushings, elbows, connections, and they check and record information on ground wire resistance, types of fuses used in the transformers, amount of oil, weight, secondary voltages, and if there are any heat issues found. The second section, consisting of the other one-sixth of the installed residential submersible transformers, is maintained by a contracting crew. All the same information as above is collected, plus the high pressure washing is performed to ensure any debris that may have accumulated in the vaults over six years is removed. An infrared report is then prepared by the washing crew for any issues noted after the washing has been completed.

3.5.3 Commercial Vault Washing

Commercial submersible distribution transformer patrols are completed twice per year for every installation by a contracting crew which performs high pressure washing. Every spring each commercial submersible transformer location is high pressure washed in order to clean out remaining salt residue which accumulates during winter conditions. The pressure washing mitigates corrosion effects on the equipment installed in the enclosures. Every vault is then washed again at the end of the fall in order to clean out any leaf and plant debris that accumulates in the vaults during the fall. The leaf and plant debris clog up sump pumps installed in the bottom of these vaults. When clogged for an extended period of time the sump pumps burn out and require replacement. If not removed the leaf and plant debris can also cause an accumulation of methane gas. Although not toxic, methane is extremely flammable and may form explosive mixtures with air. Methane is also an asphyxiant, and may displace oxygen in an enclosed space. The cleaning of these vaults will mitigate the accumulation of this gas.

3.6 Maintenance of Underground Conductors and Devices

3.6.1 Switchgear Dry Ice Cleaning

Pad mounted switching and protective device patrols are completed in two sections each year. The first section, consisting of at least one-sixth of the installed pad mounted switches, is patrolled currently by operations crews. The operations crews will open up the enclosure and confirm issues and conditions for areas such as: Obstructions, grade, accessibility, security, tank, paint, current sensors, terminations, housekeeping, motor operator, fault indicator, foundation, identification, insulators, grounding, AC service, and sump pump. Along with this review they also check and record ground resistance, perform an infrared scan, and note any additional issues. The second section, consisting of one-sixth of the installed pad mounted switches, is patrolled by a contracting crew that performs dry ice cleaning. Along with checking the above noted conditions, they spray dry ice pellets into the switchgear enclosures to clean off any contamination that may be present on the insulators, walls, blades, and barricades. The cleaning is used to help mitigate any issues regarding flashovers caused by contamination on the internal parts of the switchgear.

3.7 Maintenance of Underground Services

This account shall include the cost of labour, materials used and expenses incurred in the maintenance of underground distribution line facilities, the book cost of which is included in the underground portion of Account 1855, Services.

Example items:

Work of the following character on underground services:

1. Cleaning ducts.
2. Repairing any underground service plant.

<u>1855 Services</u>

This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the transformers or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's electrical panel. Conduit used for underground service conductors shall be included herein.

Example items:

1. Brackets.
2. Cables and wires.
3. Conduit.
4. Insulators.
5. Municipal inspection.
6. Overhead to underground, including conduit or standpipe and conductor from last splice on pole to connection with customer's wiring.
7. Pavement disturbed, including cutting and replacing pavement, pavement base, and sidewalks.
8. Permits.
9. Protection of street openings.
10. Service switch.
11. Suspension wire.

Records shall be maintained providing information on underground and overhead services separately and by capacity and function.

3.8 Maintenance of Line Transformers

This account shall include the cost of labour, materials used and expenses incurred in maintenance of distribution line transformers.

The cost shall include renewing oil, painting and the like, necessary to keep the equipment in service.

Note: All lightning arresters on the distribution system, excluding pothead arresters, are considered to be transformer equipment or devices and the maintenance thereof is chargeable to this account.

Records shall be kept to separately show costs related to overhead and underground transformers.

4 Summary

The maintenance plans contained within ensure that OHEDI meets the minimum requirements set out in the Distribution System Code. This document will be updated yearly to include any additional PM or PdM routines that are identified.

Appendix 2

Regional Planning Letter to Hydro One

Oakville Hydro
Electricity Distribution Inc.
P. O. Box 1900
861 Redwood Square
Oakville ON L6K 0C7
Telephone: 905-825-9400
Fax: 905-825-4447
email: hydro@oakvillehydro.com
www.oakvillehydro.com

June 28, 2013

Arthur Fischer
Account Executive
Hydro One Networks Inc.
PO Box 5700
Markham, Ontario L3R 1C8

Dear Arthur,

Re: Regional Infrastructure Planning in Ontario

As you may be aware, the Ontario Energy Board released *Chapter Five of the Filing Requirements for Electricity Transmission and Distribution Applications, Consolidated Distribution System Plan Filing Requirements* (the "DS Plan Filing Requirements") on March 28, 2013. The DS Plan Filing Requirements set out the information required by the Ontario Energy Board (the "Board") to assess a distributor's application involving planned capital expenditures. The DS Plan Filing Requirements are intended to ensure that, among other things, the Board's expectations for the optimization of investments reflect regional considerations.

The Board has also proposed amendments to the Distribution System Code that would require that distributors request one of three documents regarding the status of regional planning from the lead transmitter in the distributors planning region(s) and file the document(s) in support of an application for an adjustment to its distribution rates. These documents include:

- A Regional Infrastructure Plan; or
- a letter confirming the status of the Regional Infrastructure Plan; or
- a Needs Assessment Report (where participation in a regional planning process is not required).

Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") will file an application for an adjustment to its distribution rates on October 1, 2013. In accordance with the DS Plan Filing Requirements and the proposed amendments to the Distribution System Code, Oakville Hydro is requesting that Hydro One Networks Inc. ("Hydro One") provide Oakville Hydro with a copy of

Oakville Hydro
Electricity Distribution Inc.
P. O. Box 1900
861 Redwood Square
Oakville ON L6K 0C7
Telephone: 905-825-9400
Fax: 905-825-4447
email: hydro@oakvillehydro.com
www.oakvillehydro.com

the Regional Infrastructure Plan, a letter confirming the status of the Regional Infrastructure Plan or, if Oakville Hydro is not required to participate in a regional planning process, a Needs Assessment Report for the following planning regions:

- Burlington to Nanticoke Planning Region
- GTA West Planning Region

The DS Plan Filing Requirements also require that distributors consult with regionally interconnected distributors and transmitters in preparing their DS Plan. Oakville Hydro is preparing its DS Plan and would like to suggest that we arrange a meeting the week of August 12, 2013 with the appropriate staff members from Oakville Hydro and Hydro One to discuss regional planning requirements. Please contact me directly so that we can arrange a mutually convenient date and time.

Sincerely

Mike Brown, P.Eng
Vice President - Engineering and Operations
Chief Operating Officer
Oakville Hydro Electricity Distribution Inc.
Direct Line: 905-825-4469
Email: mbrown@oakvillehydro.com

Copy: Brad Colden

Appendix 3

Regional Planning Status Letter

Hydro One Network Inc.
483 Bay Street
15th Floor, South Tower
Toronto, ON M5G 2P5
www.HydroOne.com

Tel: (416) 345-5420
Fax: (416) 345-4141
ajay.garg@HydroOne.com

September 5, 2013

Mike Brown
VP - Engineering & Operations and COO
Oakville Hydro Electricity Distribution Inc.
P.O. Box 1900
861 Redwood Square
Oakville, Ontario, L6J 5E3

Dear Mr. Brown:

Subject: Regional Planning Status

In reference to your request for a regional planning status letter, please note that your Local Distribution Company (LDC) belongs to the a) GTA West and b) Burlington to Nanticoke Region, which are both in Group 1. A map showing details with respect to the 21 Regions/Groups and list of LDCs in each Region is attached in Appendix A and B respectively.

This letter is to confirm that the regional planning process has not been initiated nor has a Regional Infrastructure Plan (RIP) been developed for the sub-region within the GTA West Region or Burlington to Nanticoke Region affecting the Oakville Hydro Region. I am expecting, as per the new process, that the regional planning for the GTA West southern sub-region and the Burlington to Nanticoke Region will be initiated in 4th Qtr. of 2013. Hydro One will formally notify your organization in advance, along with other stakeholders, prior to launching the regional planning process.

The new planning process provides flexibility, during the transition period to the new process, and will ensure that both distribution and transmission planning continue to address any short-term needs, with or without, a formal regional plan. Hydro One looks forward to working with Oakville Hydro Electricity Distribution Inc. in executing the new regional planning process.

If you have any further questions, please feel free to contact me.

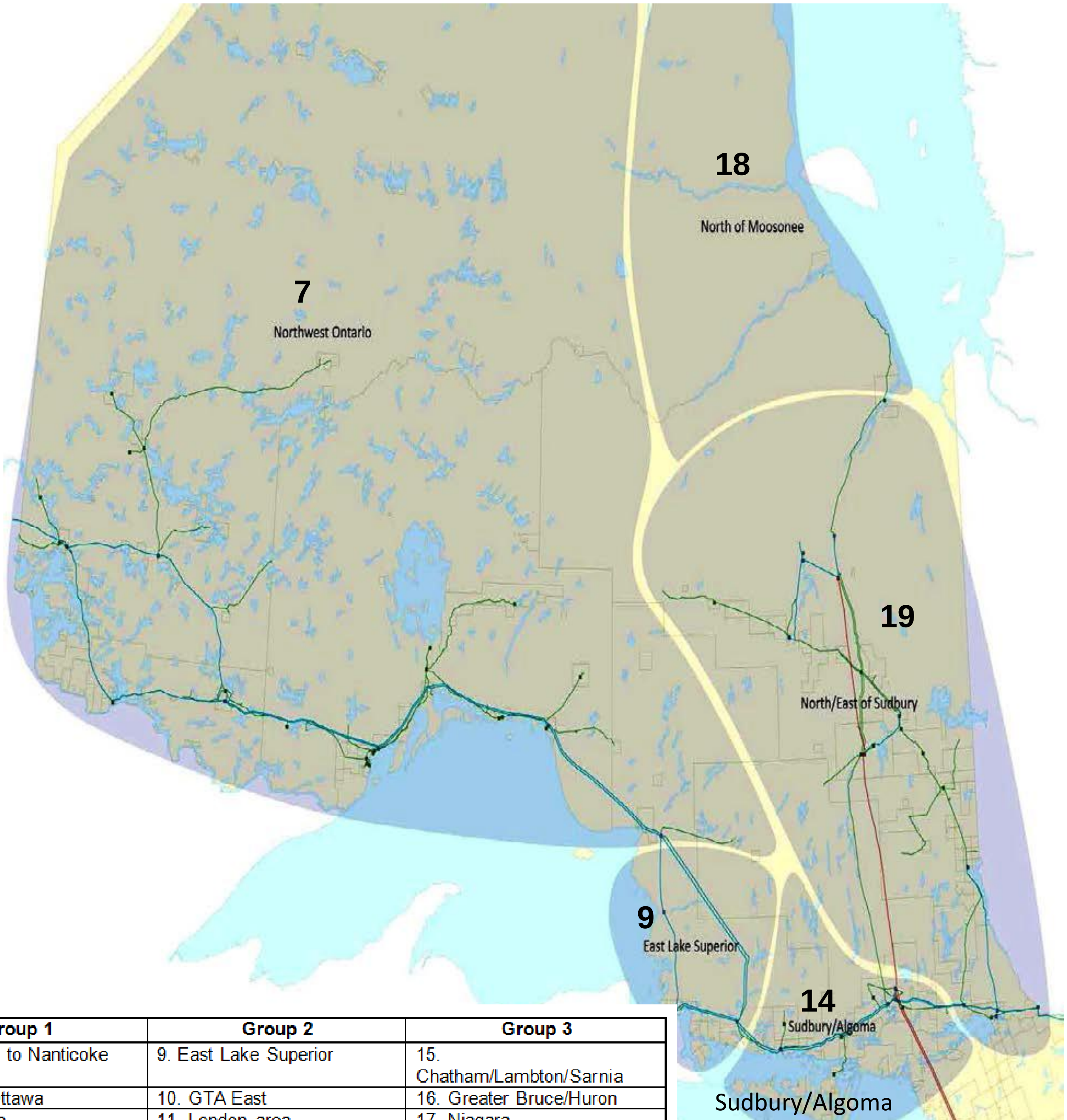
Ajay Garg

Sincerely,
Ajay Garg, P. Eng. |Manager, Regional Planning and Transmission Load Connections|
Hydro One Networks

Cc:
Brad Colden, Manager – Customer Business Relations

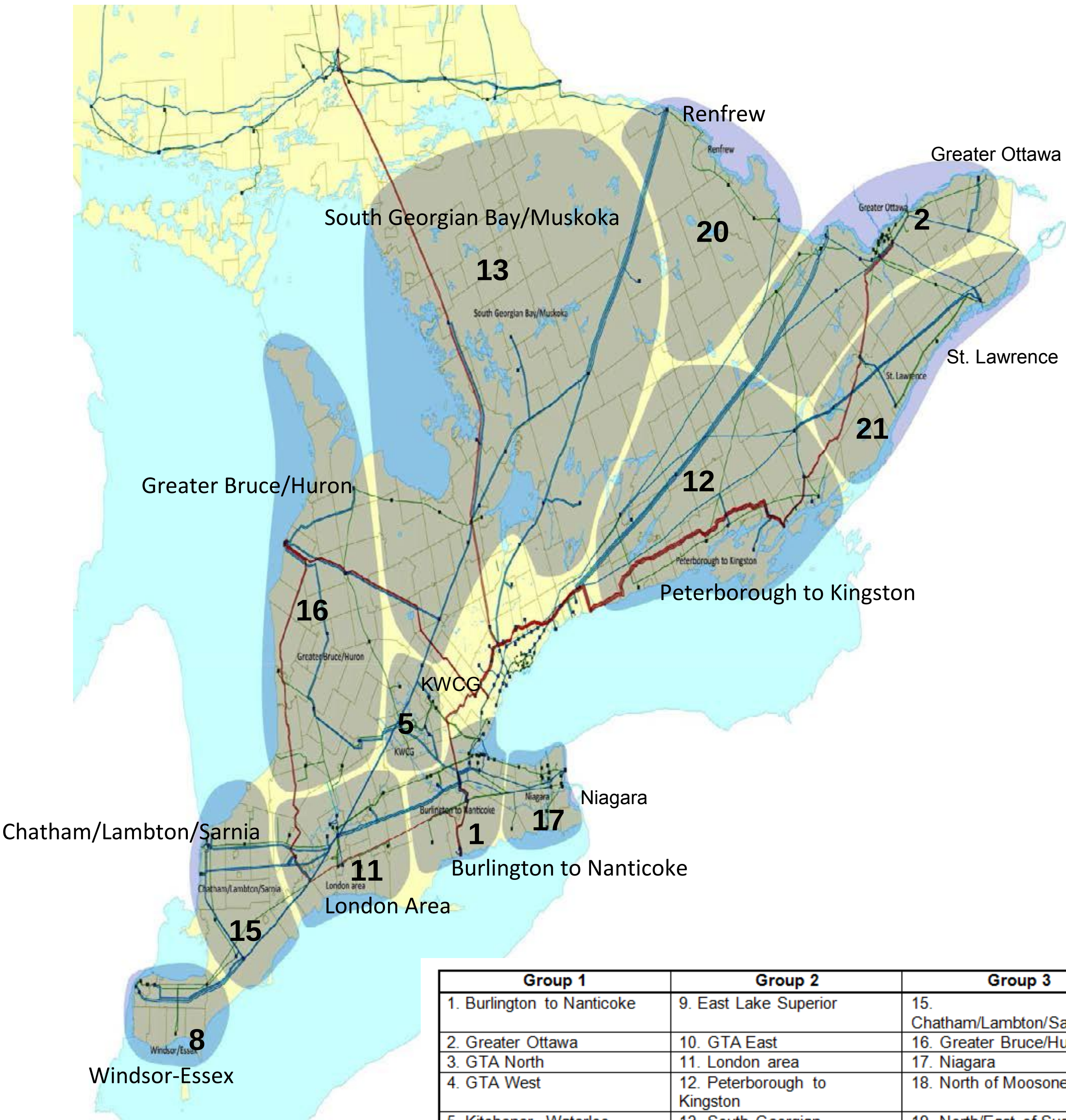
Appendix A: Map of Ontario's Planning Regions

Northern Ontario



Group 1	Group 2	Group 3
1. Burlington to Nanticoke	9. East Lake Superior	15. Chatham/Lambton/Sarnia
2. Greater Ottawa	10. GTA East	16. Greater Bruce/Huron
3. GTA North	11. London area	17. Niagara
4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Southern Ontario



Group 1	Group 2	Group 3
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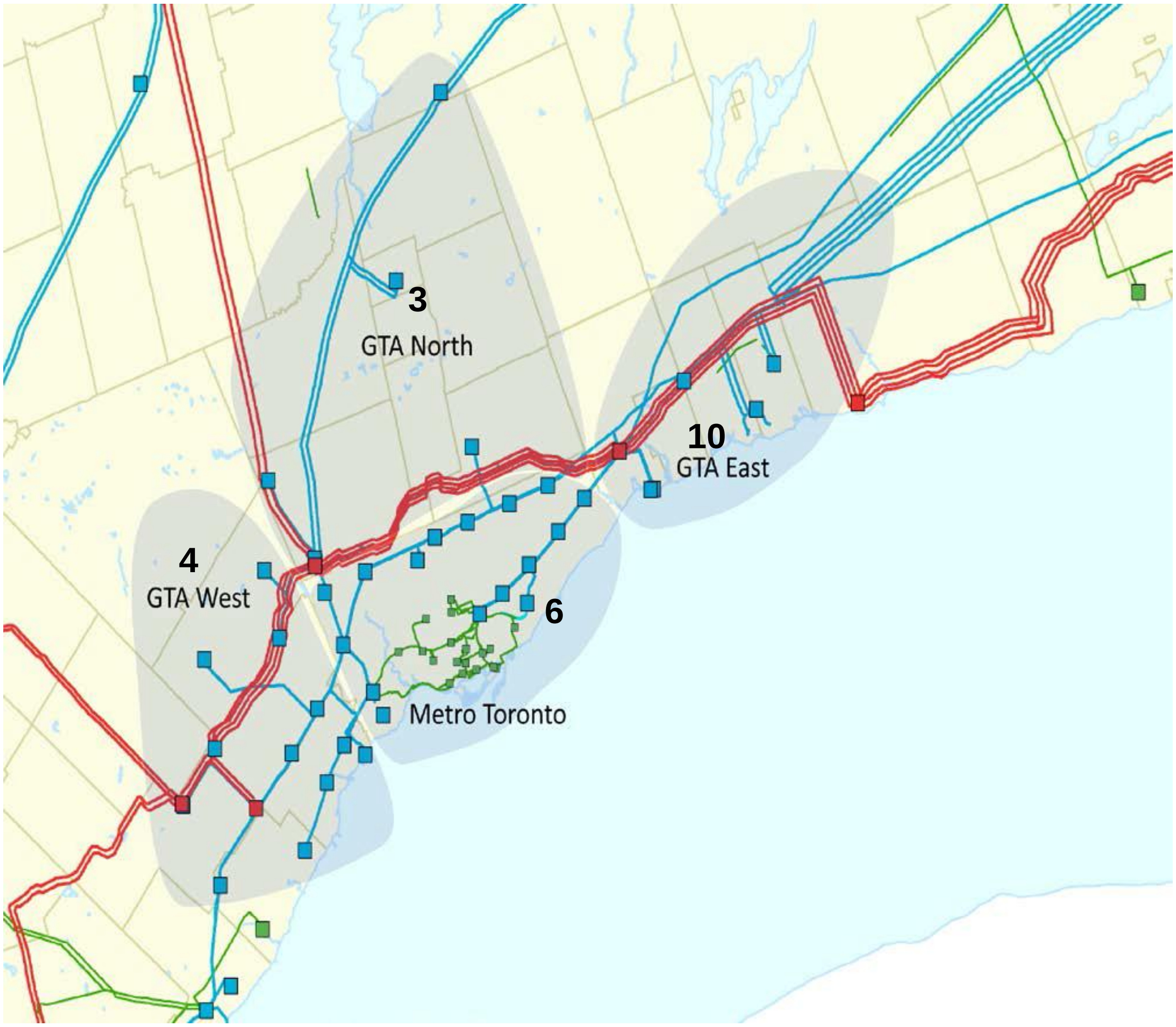
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Greater Toronto Area (GTA)



Group 1	Group 2	Group 3
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4. GTA West	12. Peterborough to Kingston	18. North of Moosonee
5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	13. South Georgian Bay/Muskoka	19. North/East of Sudbury
6. Metro Toronto	14. Sudbury/Algoma	20. Renfrew
7. Northwest Ontario		21. St. Lawrence
8. Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Brant County Power Inc. • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc. • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph ("KWCG")	• Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham-Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A →This region is not within Hydro One's territory

10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation
11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc. • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.

14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham-Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.
17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp.
18. North of Moosonee	N/A →This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.

20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

Appendix 4

Renewable Energy Generation Plan

Renewable Energy Generation Investments

2014 - 2018

Oakville Hydro Electricity Distribution Inc.

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1. EXECUTIVE SUMMARY

In its letter dated March 28, 2013, the Ontario Energy Board (the "Board"), stated that "*under the renewed regulatory framework for electricity, a distributor's investments to accommodate and connect renewable energy generation and to develop and implement a smart grid are integral to its overall capital expenditure plan. Consequently, for future distributors filing as indicated above, the Board's Filing Requirements: Distribution System Plans-Filing under Deemed Conditions of Licence – May 17, 2012 will no longer apply*". On March 28, 2013, the Board also issued Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, entitled Consolidated Distribution System Plan Filing Requirements (the "DS Plan Filing Requirements") which reflect the Board's policy direction on an integrated approach to distribution network planning. Oakville Hydro has prepared its DS Plan in accordance with these DS Plan Filing Requirements.

Section 5.1.4.2 of the DS Plan Filing Requirements requires that distributors submit information to the Ontario Power Authority (the "OPA") in relation to the Renewable Energy Generation investments identified in their DS Plan. The OPA is expected to provide a letter of comment with regards to these plans. Oakville Hydro's Renewable Energy Generation Investment Plan forms part of its overall Distribution System Plan. However, Oakville Hydro has separated its Renewable Energy Generation Investment Plan for the purpose of the obtaining OPA's review and letter of comment. The Board's expectations for the OPA's comment letter are provided in Appendix B.

The Renewable Energy Generation Investment Plan assesses the state of Oakville Hydro's existing distribution system, studies the current renewable-connected generation and near-term growth forecast, defines a strategy to accommodate the predicted renewable generation growth and describes Oakville Hydro's future Renewable Generation expenditures from 2014 through 2018.

The OPA launched the Feed-In Tariff ("FIT") program in 2009. The FIT/microFIT program generated modest interest in Oakville Hydro's service area. Oakville Hydro's connected renewable generation is currently 0.49 MW for FIT programs. Currently there are three FIT projects and 32 microFIT projects which have been connected. There are seven FIT applications in Oakville Hydro's service area waiting for a contract with the OPA.

Oakville Hydro's distribution system is a robust, integrated network throughout the Town of Oakville. Adequate planning and proactive infrastructure projects have made the distribution network well equipped to handle forecasted renewable generation, except for areas supplied by two Hydro One-owned transmission stations supplying Oakville Hydro which have capacity restrictions due to short circuit levels. Oakville Hydro is working with the transmitter (Hydro One) to alleviate these restrictions, but would have to accept higher short circuit limits than set out in the Transmission System Code. Oakville Hydro plans to study the risk of this change and make a determination to accept, or not accept the higher limits by year end 2013. If this restriction is lifted, Oakville Hydro does not expect a significant increase in FIT applications, based on information currently available.

Based on Oakville Hydro’s 2011 to 2013 FIT/microFIT data and the future assumptions, it is estimated that the connection of Renewable Energy projects under FIT and microFIT programs will remain steady between 2014 and 2018. The calculated remaining capacity and the projected demand for renewable energy indicate that Oakville Hydro is ready to connect future renewable generation projects.

Consequently, Oakville Hydro has not included any capital expenditures related to renewable energy generation in its Distribution System Plan. There has been modest interest in the FIT program that would require Renewable Energy Generation Investments. In addition, there are no additional OM&A costs proposed related to renewable energy generation as Oakville Hydro is able to manage workload using existing staff to process microFIT/FIT applications and all the related requirements that currently exist.

2. CURRENT ASSESSMENT

2.1 The Oakville Hydro Distribution System

Oakville Hydro is a local distribution company responsible for the distribution of electricity to approximately 65,000 homes and businesses within the Town of Oakville. It is a subsidiary of Oakville Hydro Corporation whose sole shareholder is the Town of Oakville. Oakville Hydro relies on 1,529 km of circuits to deliver energy and power to its customers. It receives power from Hydro One Networks Inc. and delivers electricity to its customers via five high voltage transformer stations, four owned by Hydro One and one by Oakville Hydro.

2.2 Existing Distributed Generators

As of July 2, 2013, Oakville Hydro has connected three Feed-In Tariff (FIT) projects for a total of 0.49 MW of renewable generation. In addition, Oakville Hydro is aware of seven pending FIT applications from renewable generators over 10 kW in the Oakville service area, totaling 2.075 MW. There are also currently 32 microFIT customers totaling with a total capacity of approximately 200 kW. The total FIT breakdowns by transformer station are shown in Table 1.

Table 1: Oakville Hydro FIT Projects (as at August 12, 2013)

Transformer Station	Bus #	Connected FIT Customers	Connected FIT - Total Capacity (MW)	Pending FIT** Customers	Pending FIT** - Capacity (MW)
Oakville TS (1)	E	1	0.06	2	0.825
Oakville TS (1)	Z	2	0.43	1	0.250
Bronte TS (1)	Q	-	-	1	0.250
Bronte TS DESN1 (1)	BY	-	-	1	0.300
Trafalgar TS(1)	BY	-	-	1	0.250
Palermo TS(1)	BY	-	-	-	-
Glenorchy MTS	J	-	-	-	-
Glenorchy MTS	Q	-	-	1	0.500
TOTAL		3	0.49	7	2.375

(1) Hydro One owned

***Pending applications with the OPA may or may not proceed depending on their eligibility review process.*

2.3 System Capability Assessment for Renewable Energy Generation

The estimated capability of Oakville Hydro's distribution system to accommodate renewable energy generation connection at each transformer station is shown in Table 2 below.

At this time Oakville Hydro is not aware of specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

There are two Hydro One-owned transformer stations namely, Palermo and Trafalgar where there are short circuit capacity restrictions related to the connection of renewable generation, within the upstream transmission system. However, the remaining stations have sufficient short-circuit capacity to accommodate the type of distributed generation that Oakville Hydro has seen so far. Most of the renewable energy projects proposed in Oakville Hydro service area are inverter-based with limited fault contribution to Oakville Hydro's distribution system. It is unlikely that the fault contribution from the anticipated distributed generation will cause the transformer stations to reach the short-circuit capacity limits.

Oakville Hydro is working with the transmitter to alleviate the restrictions at Palermo and Trafalgar, but would have to accept higher short circuit limits than set out in the Transmission System Code. Oakville Hydro plans to study the risk of this change and make a determination to accept, or not accept the higher limits by year end 2013. If this restriction is lifted, Oakville Hydro does not expect a significant increase in FIT applications, based on information currently available.

Table 2: The estimated capability of Oakville Hydro's distribution system

Transformer Station	Bus Name	Feeder Name	Voltage (kV)	Capacity for GEN (MW)	Connect GEN (MW)	Remaining Capacity (MW)
Oakville TS (1)	E	M43,M49,M51	27.6	53.10	0.06	53.04
Oakville TS (1)	Z	M44,M50,M52	27.6	49.40	0.43	48.97
Bronte TS (1)	Q	M23,M24	27.6	54.00	0.00	54.00
Bronte TS DESN1(1)	BY	M1,M2,M3,M4,M5,M7,M8	27.6	63.90	0.00	63.90
Trafalgar TS (1) (2)	BY	M4,M5,M6,M7,M8	27.6	0.00	0.00	0.00
Palermo TS (1) (2)	BY	M2,M4,M7,M8	27.6	0.00	0.00	0.00
Glenorchy MTS	J	M15,M17,M19	27.6	17.10	0.00	17.10
Glenorchy MTS	Q	M14,M16,M18	27.6	15.60	0.00	15.60
Total				253.10	0.49	252.60

(1) Hydro One Owned TS

(2) There is No Generator Connection Capacity Due to lack of Short Circuit Capacity

In addition to the above station available capacity information, the cumulative generation connections are limited on an individual feeder basis as follows:

- Feeders operating at 27.6 kV – 19 MW
- Feeders operating at 13.8 kV – 9.6 MW
- Feeders operating at 4.16 kV – 1.45 MW

Based on the low volume of current connections and the volume of existing generators in the application phase, Oakville Hydro does not anticipate or forecast a high volume of connection applications over the 2014 to 2018 planning horizon.

At this time, Oakville Hydro has one potential embedded distributor – Milton Hydro. There are no known constraints for an embedded distributor that may result due to renewable generator connections, other than capacity limitations outlined above.

3. PLANNED DEVELOPMENT

3.1 Projected Renewable Generation Growth

To date, the Renewable Generation installations in Oakville Hydro's service area consist of rooftop solar PV smaller than 500 kW. As indicated by the OPA, there are seven small FIT applications under the FIT 2 program with a total proposed capacity of 2.375 MW (refer to Appendix A). Due to the 200 MW provincial limit for small FIT applications, it is reasonable to estimate that only some of these applications will be awarded a conditional offer under the FIT 2.0 program in 2013. It is also reasonable to expect that the remaining customers who do not receive a FIT contract under FIT 2.0 in 2013 will choose to pursue at a later time.

Based on Oakville Hydro's 2011-2012 FIT/microFIT data and the future assumptions, it is estimated that the connection of Renewable Energy projects under FIT and microFIT programs will remain steady between 2014 and 2018. This estimate assumes that the OPA does not significantly change the program rules and rate calculation methodology.

In general, it is estimated that Oakville Hydro has enough remaining station capacity and distribution infrastructure to accommodate the demand for renewable energy projects under FIT/microFIT program from 2014 to 2018.

3.2 OPA Consultation

Oakville Hydro consults with the OPA on a regular basis as new contracts are approved and will continue to do so in the future. The OPA’s letter of comment with respect to Oakville Hydro’s Renewable Energy Generation Plan is provided in Appendix B.

4. PLANNED INVESTMENT

Under the rules for connecting renewable energy projects in the Distribution System Code, Oakville Hydro will be responsible for funding new feeder assets required to connect FIT generators to a maximum of $90,000 per MW. To date, there has been limited interest in FIT generation projects that would require construction of new feeder assets. No renewable energy generation investments for the period 2014 - 2018 are expected, in order to accommodate the renewable energy generation connections.

From an OM&A perspective Oakville Hydro has been able to manage the workload related to processing renewable energy applications using existing staff for responding to the microFIT inquiries, conducting the site visits, preparing the offers to connect and microFIT data entries. Oakville Hydro continues to anticipate similar low volume activity of applications in the future and has not included any OM&A costs in the Test year.

4.1 Overall Assessment

Based on a calculated remaining maximum capacity and the projected generation projects Oakville Hydro feels confident that it has capacity in place to accept future renewable generation projects.

Appendix A: Proposed small FIT applications

The proposed small FIT applications in Oakville Hydro service area as provided by the OPA are provided in the following table.

Number of Applications	Capacity (kW)	LDC Name - TS Name, Upstream Feeder Name, Voltage (as indicated by the applicant)
1	300	Oakville Hydro EDI – Bronte TS, M8, 27.6kV
1	250	Oakville Hydro EDI – Oakville TS, M50, 27.6kV
1	250	Oakville Hydro EDI – Trafalgar TS, M5, 27.6kV
2	825	Oakville Hydro EDI – Oakville TS, M43, 27.6kV
1	250	Oakville Hydro EDI – Bronte TS, M24, 27.6kV
1	500	Oakville Hydro EDI – Glenorchy MTS, M14, 27.6kV

Appendix B: OPA Letter

As per Section 5.1.4.2 of the DS Plan Filing Requirements, the Board expects that the 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 Renewable Energy Generation investments; and
- Whether the Renewable Energy Generation investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

The Board may postpone processing an application where a comment letter from the OPA has not been filed in accordance with this requirement.

OPA Letter of Comment:

Oakville Hydro Electricity Distribution Inc.

Renewable Energy Generation Investments

September 12, 2013

ONTARIO POWER AUTHORITY

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 ("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.

Oakville Hydro Electricity Distribution Inc. – Distribution System Plan

The OPA received Renewable Energy Generation Investments Plan ("Plan") from Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro") on August 15, 2013. The OPA has reviewed the Plan and provided its comments below.

OPA FIT/microFIT Applications Received

On page 4 of its Plan, Oakville Hydro indicates that currently it has connected 3 FIT projects totalling 490 kW of renewable generation capacity and 32 microFIT projects totalling 200 kW of capacity. Additionally, Oakville Hydro is aware of 7 pending FIT applications totalling 2,075 kW of capacity that may connect to its distribution system.

According to OPA's information, as of August 30, 2013, the OPA has received and offered contracts to 10 FIT projects, totalling 2,865 kW of capacity, which remain active to date. Of these, 3 FIT projects representing 490 kW have reached commercial operation. Additionally, the OPA has received and offered contracts to 36 microFIT projects, totalling 236 kW of capacity, which remain active to date.

The OPA finds that Oakville Hydro's Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

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Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

The OPA notes that Oakville Hydro is part of "Group 1" for regional planning prioritization (underway - 2014), and although bulk transmission and regional planning activities have taken place or are currently underway in some parts of the area, neither a Regional Infrastructure Plan, nor an Integrated Regional Resource Plan has been completed for Oakville Hydro's service territory. Oakville Hydro has provided the OPA with long-term load forecasts to support these planning initiatives. As a result, the OPA is unable to comment on whether Oakville Hydro's renewable energy generation investments are consistent with a Regional Infrastructure Plan. In fact, in the section entitled *Planned Investment* on page 9 of the Plan, Oakville Hydro indicates that:

"No renewable energy generation investments for the period 2014 - 2018 are expected, in order to accommodate the renewable energy generation connections." and,

"Based on a calculated remaining maximum capacity and the projected generation projects Oakville Hydro feels confident that it has capacity in place to accept future renewable generation projects."

The OPA also concurs with Oakville Hydro that there is ongoing consultation with the OPA with respect to new contract information to facilitate renewable energy generation connections, and that this will continue.

The OPA looks forward to working with Oakville Hydro in the execution of regional planning once that process is triggered, and appreciates the opportunity to comment on the information provided as part of Oakville Hydro's Renewable Energy Generation Investments Plan.

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Appendix 5

Smart Grid Strategy

Smart Grid Strategy
(Oakville Hydro)

Overview

Developing a ’smart grid’ electricity system has been an evolving global vision over the past 15 years. In 2010, the Ontario Smart Grid Forum defined Smart Grid as follows:

- “*A smart grid is a modern electricity system. It uses sensors, monitoring communications, automation and computers to improve the flexibility, security, reliability, efficiency, and safety of the electricity system. It offers consumers increased choice by facilitating opportunities to control their electricity use and respond to electricity price changes by adjusting their consumption. A smart grid includes diverse and dispersed energy resources and accommodates electric vehicle charging. It facilitates connection and integrated operation. In short, it brings all elements of the electricity system – production, delivery and consumption closer together to improve overall system operation for the benefit of consumers and the environment*.”

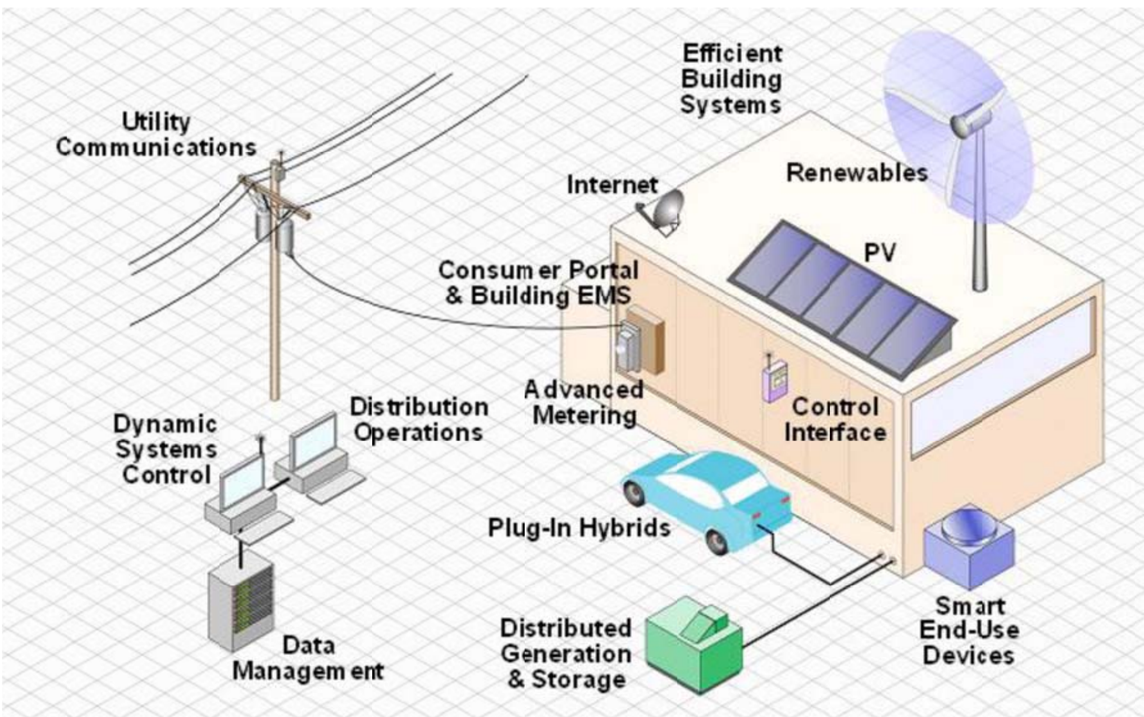
The outcome of this vision being achieved, is dramatically greater visibility and control of the electricity network, support for distributed generation, a more interactive relationship with customers to manage energy use, while maintaining the highest standards for safety and overall system security.

Key Drivers of Smart Grid Evolution (Ontario)

In Ontario, regulatory direction through the Ministry of Energy has initiated and encouraged / mandated significant investment in the operating infrastructure and IT systems in support of an evolving electricity system. The recent implementation of smart meters (Advanced Metering Infrastructure (AMI)) and associated provincial Meter Data Management / Repository (MDM/R) IT system to support Time of Use end user consumption visibility and capabilities is an example of this direction. In addition, Ontario’s Green Energy Act promotes and enables renewable energy and distributed generation in all jurisdictions across the province. The Ontario Energy Board (OEB), as part of its Cost of Service (COS) application process by LDCs, requires each LDC to file a Smart Grid Plan as a means to demonstrate its forward-thinking views on distribution system evolution. In 2012 the Ministry of Energy, in an effort to promote technological innovation in the area of smart grid, selectively awarded funds for demonstration / pilot projects (between vendors / LDCs). Increasing consumer expectations around electricity system robustness and reliability, in order to meet their life style needs is another key driver.

Addressing Utility Challenges with Smart Grid	
Challenge	**Smart Grid Benefits**
Customer Control	• Information and Incentives for Reduced or More Intelligent Energy Usage • Real Time Data Access • Behind the Meter Services • Improved Customer Service and Outage Communication
Power System Flexibility	• IT System Integration • Analytics for Decision Support • Connected Mobile Work Force • Self Healing Grid with Automated Switching and Protection Systems
Adaptive Infrastructure	• Balances Supply and Demand • Manages Power Quality • Monitors and Controls Renewable Energy Sources • Maintains Grid Stability as Renewably Energy Sources are Added • Meets Environmental Targets and Regulatory Requirements

Customer-Centric Smart Grid Representation:



Source: Electric Power Research Institute (EPRI – US)

Smart Grid Strategy (Oakville Hydro)

Oakville Hydro's Smart Grid strategy will be to grow and develop the distribution grid utilizing a combination of good utility distribution practice coupled with emerging technologies & systems. Oakville Hydro's long term strategy is to evolve its operating distribution system and associated IT systems capabilities to align with its over-arching smart grid goals. Oakville Hydro plans to leverage the capabilities of current system assets to enhance future capabilities (e.g. smart meters integrated into Outage Management System). In addition, it will make prudent asset management decisions around replacing selected end-of-life equipment and communication infrastructure, with choices that align with this evolving strategy. Oakville Hydro will ensure that all smart grid projects align with Oakville Hydro's Strategic Plan, by including them in the capital project portfolio to be evaluated and prioritized as set out in the Asset Management strategy.

Oakville Hydro's Smart Grid over-arching goals are as follows:

Customer Control

1) Enhance customer experience associated with control of energy usage.
2) Increase visibility / currency on system outages
3) Connect renewable generation (e.g. solar) and take advantage of plug-in and hybrid vehicles as choice of transportation

Power System Flexibility

4) Improve distribution system reliability, performance and responsiveness
5) Equip the distribution system to enable two-way flow of electricity
6) Improve operating efficiencies through distribution automation, e-mobile capabilities and IT system integration (e.g. AMI, GIS, SCADA, OMS)

Adaptive Infrastructure

7) Improve power quality and energy efficiency using advanced system tools and controls, to monitor and reduce distribution losses
8) Enhance asset efficiency through system monitoring to fully utilize and extend life of existing assets

Over the next few years, Oakville Hydro will need to continue to reinforce the foundations of its distribution system (e.g. switching, monitoring and communications infrastructure) and enhance / integrate its operating and information systems in order to achieve these goals. These changes will involve continued enhancements of current engineering and operations technology platforms (GIS and SCADA) as well as planned integration into a new platform (Outage Management System) currently under development. A new level of sophisticated operational capabilities is evolving that will accept all forms of distributed generation and provide increased reliability through switching flexibility and automation features such as self-healing distribution feeders. The attached Appendix, included with this Smart Grid strategy, provides more detailed near and mid-term plans to operationalize this strategy.

Timing of smart grid investments will be, as mentioned, somewhat dependent on upgrades to Oakville Hydro's distribution system facilities through expansion or renewal. The rate of customers' adoption of renewable generation and consumer technologies will also have an impact on Oakville Hydro's anticipation of smart grid investments. Plug-in electric vehicles are starting to enter the market but adoption is slower than anticipated. These entrants, plus the potential for growth in electric public transportation, is expected to be longer term, but none the less, a significant aspect of smart distribution systems. Oakville Hydro will continue to monitor the situation and work towards enabling their roll out through collaborative ventures.

Smart Grid Strategy (Oakville Hydro)
Appendix

Capabilities Assessment (Current and Planned)

Oakville Hydro has many activities and initiatives currently underway and / or in the planning stages that enable the capabilities required to achieve its smart grid goals. They have been categorized as noted below. Each category consists of common themes and contains the associated current state and/or directional plans.

1. **Existing Areas of Operational Excellence** – capabilities that are already present that will be leveraged to enable/deliver on our Smart Grid goals.
2. **Customer Control** – advancements and initiatives that positively impact the customer, providing improvements in both experience and value.
3. **Power System Flexibility** – enhancements made to the distribution system that delivers improved system reliability, problem detection and mitigation.
4. **Adaptive Infrastructure** – equipment or system advancements that optimize business processes, in order to enhance resource effectiveness and/or generate cost efficiencies.
5. **Smart Grid Initiatives** – electric vehicles plus smart grid pilot projects that are funded by the MOE and/or approved by the OEB.

1. Existing Areas of Operational Excellence:

- **Capabilities that are already present that will be leveraged to enable / deliver on Smart Grid goals**

a) Advanced Metering Infrastructure (AMI)

Current State

Oakville Hydro has implemented a Sensus FlexNet AMI network capable of providing remote meter reading to approximately 65,000 smart meters, for the purposes of Time-of-Use billing. Oakville Hydro's AMI network utilizes a licensed radio frequency (RF) network for the collection and transmission of metering information from each meter point to meter data collection and storage systems. Each meter point uses the RF network to wirelessly transmit data to five Tower Gateway Base stations (TGBs) situated throughout Oakville. Once meter data reaches these towers, the data flows into the Regional Network Interface (RNI) via Oakville Hydro dedicated fibre optics. The RNI is the single point of collection for all meter data within the Sensus AMI network. This system is a flexible, multi-application network for Smart Metering with the potential for Distribution Automation and Demand Response. This system is capable of supporting single phase meters, polyphase meters, and additional smart devices. The AMI network will enable the future grid modernization initiatives due to its reliability, availability, scalability, low latency, ability to provide 'over the air' upgrades, and its open standards network architecture.

Oakville Hydro and Sensus have collaborated to ensure that the AMI system is secure. Multi-layered security (from endpoint to user interface) has been a priority since the implementation of AMI. Further measures also include a fully integrated encryption and enhanced key management protocol to safeguard Oakville Hydro's AMI system from external threats.

Directional Plans

All of the information that is harvested from the AMI network resides in the Operational Data Store (ODS). The ODS is a scalable, adaptable system that can meet Oakville Hydro's customer growth and provides customizable options for the addition of future functionality. The ODS currently stores, validates and processes large volumes of data for billing, settlements and other reporting and reconciliation obligations. The ODS is expected to supply meter outage or 'last gasp' information to the Control Room Operator to assist in outage restoration. This outage data will be linked to the Outage Management System (OMS) that is currently in the development stage. Future integration plans with ODS include meter disconnect/reconnect capability linked with the Customer Information System (CIS), transformer to customer network connectivity data linked to the Geographic Information System (GIS), and seasonal load profiles tabulated by transformer and linked to the power engineering software analysis tool (CYME) for load forecasting and analysis.

Timeline

The formatting for outage messaging from the ODS to OMS has been developed and tested using sample data on test servers. This capability is expected to be operational on the live SCADA system in 2013.
Integration to CIS for meter disconnect/reconnect, GIS for customer/transformer network connectivity, and CYME for load forecasting and analysis are planned for 2014.

b) Embedded Field Communications for System Monitoring & Control

Current State
Oakville Hydro first started deploying remotely-operable switches in the early 1980's. Currently there are 120 controllable switches on the 27.6kV distribution system that are used for fault indication, outage restoration, load control and load monitoring. Of these 120 switches, 37 of them have been installed since 2009. These switches are primarily controlled using an Industry Canada licensed 400 MHz radio channel. With 30 separate feeder circuits in service supplying the 27.6kV distribution system, this equates to on average 4 controllable switches per circuit that are used to isolate failures and restore power remotely from the Control Room.

Currently there are 2 Municipal Substations with 13.8kV secondary voltage, 17 Municipal Substations with 4kV secondary voltage, and 1 Transformer Station (Glenorchy MTS) with 27.6kV secondary voltage. All Oakville Hydro substations, as well as Glenorchy MTS, are connected to SCADA via fibre optics.

To enhance fault locating capabilities, Oakville Hydro has installed 7 communicating remote fault indicator collectors that are wirelessly connected to fault indicators that monitor a total of 17 separate primary electrical circuits. For these 17 primary electrical circuits, the fault indicators communicate back to the SCADA system and report instantaneous load information for load control purposes. They also indicate detection of fault current for outage restoration purposes

Directional Plans
Plans are in-place to install more of these remote fault indicator collectors to monitor an additional 11 electrical primary circuits. In addition, there are pilot projects currently underway to trial new overhead and underground indicator technologies such as energy harvesting that eliminate the need for a battery maintenance program. All of Oakville Hydro's communicating fault indicators communicate back to SCADA using an HSPA cellular network.

Timeline
The pilot projects for underground indicators and energy harvesting overhead indicators are currently in place. It is expected that the pilot project findings will be used to drive additional investment in fault indicator technology in 2014.

c) Experience with Modern Intelligent Electronic Device (IED) Technology

Current State
Oakville Hydro was an early adopter of solid state Intelligent Electronic Device (IED) technology. IEDs consist of computerized equipment that is used for system monitoring, operation, and diagnostics. When the first remotely-operable switches were installed in the early 1980's, there wasn't an off the shelf solution for switch control and SCADA (System Control And Data Acquisition) communication, so the required IEDs were wired, commissioned, and installed by Oakville Hydro. Similarly, Oakville Hydro made the switch from electro-mechanical protection relays to three phase solid state IEDs in the late 1980's when the technology became available for substation feeder protection.

In the last three years, Oakville Hydro's capital program has included new remotely-operable switches, municipal substation breaker and transformer replacement projects, and the Glenorchy transformer station, all of which include IED technology with varied requirements. It would be difficult to maintain & operate all of this equipment if there was a different IED technology platform with each project, so Oakville Hydro has standardized on Schweitzer Engineering Laboratories (SEL) and General Electric (GE) IEDs. These two technology platforms are widely used in the utility industry, and have been used by Oakville Hydro for power transformer monitoring, switch control & monitoring, municipal substation feeder protection, and all of the Glenorchy MTS transformer station protection elements required by the transmission code.

d) 24/7 Operations Control Room

Current State

Oakville Hydro's 24/7 Operations Control Room uses the SCADA (System Control and Data Acquisition) System to both monitor and control all 120 remotely-operable switches, 7 communicating remote fault indicator collectors, 19 Municipal Substations, and the Glenorchy Transformer Station. Considering that the 120 remotely-operable switches are deployed across the entire 27.6kV distribution system which consists of 30 feeders, this equates to on average 4 remotely operated switches per feeder. With the addition of the Glenorchy Municipal Transformer Station (MTS) in 2011, required enhancements to Operator training programs and Operations Control Room operating procedures & policies were made to comply with the strict IESO Transmission System operating requirements. In case of emergency, there is the ability to move these Operations Control Room capabilities from 861 Redwood Square to the Backup Control Room at Glenorchy MTS.

Oakville Hydro is in a unique transmission grid location in that three separate Hydro One transmission lines are utilized to supply electricity to the Town of Oakville. In addition, this supply consists of four Hydro One-owned transformer stations and one Oakville Hydro-owned transformer station. This configuration results in frequent load transfer requests from Hydro One, driven not only by transformer station thermal load, but load restrictions in the transmission system. With these load transfer pressures combined with day-to-day transfers for Oakville Hydro capital projects and maintenance, Oakville Hydro's Operators have become very proficient in using the SCADA system combined with loading data from substations, remote-operable switches, and communicating fault indicators, to maintain the integrity of the distribution system.

Oakville Hydro's Operations Control Room also has a well documented and managed procedure concerning outage restoration and customer communication, implemented in collaboration with the Customer Service Department. In the event of an outage the Operator can forward all phone calls to the Customer Service Representatives and focus on restoration and communication. The Customer Service Representatives receive all phone calls and forward all pertinent information to the Operator. The Operator issues regular outage updates with estimated restoration time to an internal email distribution list, which can then be sent to external contacts as required. Once all power is restored an outage report is both circulated internally and posted to the public website.

Directional Plans

Operator capabilities will continue to grow with respect to system operations and restoration activities with the planned 2013 implementation of OMS. The OMS will bring capabilities that promote outage messages to the Oakville Hydro website and to customer portable electronic devices (PEDs). Also, the establishment of an IVR system will be evaluated to streamline customer service and outage reporting.

e) Geographic Information System (GIS)

Current State

Oakville Hydro initiated the conversion of its auto-cad developed, paper-based distribution system records to an intelligent GIS record in 2010. We achieved all of our key milestones in 2010, 2011, 2012 and on-track for completion in 2013.

Oakville Hydro rolled out a mobile GIS application in February 2013. The initiative reduces the amount of paper prints issued to the field crews and enables redline reporting/communication between Operations and Engineering.

Directional Plans

Going forward, the GIS system offers a variety of productivity features. Some examples are listed below:

- Redline capabilities
- Improving accuracy and currency of distribution system data
- Decrease reconciliation costs between Engineering & Operations for field information
- Ease in locating documents - one repository location for Construction and As-build drawings
- Improved records accuracy will reduce amount of field verification
- Integration of distribution system network model into OMS/SCADA, CYME, and ODS as a valuable information system for Operations Control Room, Engineering Analysis, and Asset Utilization.
- Other operational savings will also be realized in the areas of:
    - Improving information for locates
    - Improving information for asset management & maintenance
    - Locating data and documents
    - Report discrepancies within Network from field vantage
    - Service calls and outage management

Timeline

These productivity features are expected to materialize in 2013.

2. Customer Control

- **Advancements and initiatives that positively impact the customer, providing improvements in both experience and value.**

a) Customer Engagement Strategy

Current State

Oakville Hydro is a customer-centric utility, are constantly working to ensure that our customers have the information they need on various programs and initiatives. Oakville Hydro promotes OPA-Contracted Province-Wide CDM Programs to its customers in a number of ways, including:

- Mass market advertising (newspaper advertising, direct mail, billing inserts, on-bill messaging, on-line advertising, etc.).
- Information concerning CDM programs as well as tips for energy saving on OHEDI's website.
- Sponsorship / participation in local community events such as home / lifestyle shows to promote CDM programs and awareness; flyers describing CDM programs are available at these events.
- Support for public environmental / conservation awareness events such as Earth Day and Eco-Fest.
- For business customers, "lunch & learn" sessions are provided periodically to provide information concerning CDM programs.

Customer feedback is a critical aspect of our strategy, including feedback regarding Smart Grid. A survey was conducted in March 2012 with 1,385 households contacted to take part and provide feedback. Select survey questions focused on smart meters, Smart Grid, and conservation & demand management, with the purpose of determining what customers think about all three categories. In relation to the Smart Grid, we wanted to determine the level of customer knowledge and awareness for Smart Grid, and find out if there is customer support for Oakville Hydro to pursue Smart Grid initiatives.

Oakville Hydro has also engaged the Oakville Town Council on Smart Grid initiatives, including field automation. The Council supported our direction and plans including:

- Acknowledging the number of existing switch locations that are controlled from the Control Room, the use of SCADA, and the role of each in outage restoration.
- Support for continued investment in both remotely controlled switches and switching locations supplied from two sides that automatically operate to select the energized side in the event of an outage (field automation).

Directional Plans

Customer Education will continue to be a focus of our engagement strategy focusing on communicating the features and benefits of Smart Grid to our customers in order to build understanding. A variety of media will be used for this purpose including website, bill inserts, flyers, news release, community events, and customer service representative training.

b) Data Access

Current State

Oakville Hydro has implemented “eCare”, an online web presentment service that allows smart metered customers the ability to access their historical meter data. Customers can graph their electricity consumption and monitor energy usage in kWhrs and in cost of energy. Demand side management screens compares customers usage to similar accounts in their neighbourhood and helps customers understand their consumption patterns and load profiles. It also helps them identify which loads/appliances use most electricity so they can practise energy management and conservation. Oakville Hydro also provides on-bill monthly historical energy usage for previous 12 months so customers can readily compare energy usage over a period of time.

Directional Plans

Going forward, we plan to introduce the capability for alert notifications regarding consumption and price, supply charts with weather trends, provide usage comparison information in terms of dollar value, and enable our customers to download their consumptions data.

Timeline

Some of the additional functionality is expected to materialize in 2013, with the remainder in 2014.

c) In-Home Display (IHD)

Current State

The existing in-home displays are limited to the PeakSaver program offering.

Directional Plans

Our AMI system has enabled in-home functionality that ties in with consumption data. We have begun rolling out our PeakSaver+ CDM program which provides all customers who sign up for the program an IHD free of charge. After enrolling in the program the customer owns the IHD with 2 choices:

1. Currently available is a Blueline IHD package which consists of a sensor that mounts on the meter and a Blueline Powercost monitor (IHD).
2. In the near future (potentially 2013), there is an Android tablet to be market-ready pending approval from Sensus that would include a gateway device for web based communications for our customers that would support development of future CDM programs and other potential opportunities.

Timeline

The Peaksaver+ program runs until end of 2014.

d) Energy Management Systems

Current State

The PeakSaver+ CDM program is a demand response program that allows the IESO/OPA to control customer A/C, and /or electric water heaters and/or pool pumps during peak demand periods in the summer months.

Directional Plans

In addition the Android gateway option also supports control of various loads within their home (e.g. appliances). Loads are controlled via paging using switches mounted directly on the loads.

Timeline

The PeakSaver+ program runs until end of 2014.

e) Personal Electronic Devices (PEDs)

Directional Plans

PEDs will have the capability to receive outage status updates once the OMS is operational in 2013.

f) Multifaceted Outage Communications Scheme

Directional Plans

The OMS currently under development will provide improved communications on status of outages to our customers and key stakeholders both for planned and unplanned events. The OMS will be capable of handling call entry either using a call display interface or an Interactive Voice Response (IVR) system to save time for the Operator in taking input from affected customers. Once this information is combined with outage data from the AMI, the system recommends outage cases with the predicted fault locations allowing the Operator to dispatch crews to these key locations to investigate.

With this information, as the outage restoration progresses, Oakville Hydro will be able to provide outage updates and reports using a variety of media outlets including email, twitter, webpage updates, etc. This will serve to keep all stakeholders informed and set appropriate expectations for the restoration of power.

Timeline

These additional outage communications capabilities are expected to start materializing in 2013.

3. Power System Flexibility

- **Enhancements made to the distribution system that deliver improved system reliability, problem detection and mitigation.**

a) Outage Management System (OMS)

Directional Plans

Oakville Hydro is engaged in a joint development project with Survalent (SCADA system vendor) to develop, test and implement a new Outage Management System directly integrated into our existing SCADA system platform with links to GIS, AMI, ODS, and (CIS) customer data. This initiative represents the first OMS system in Ontario to be built directly into the SCADA software already in use by Control Room Operators.

The proposed OMS software will draw on information from the existing Harris CIS, Sensus AMI, and GIS platforms as a powerful tool for the Control Room operators to use when responding to system outages of any magnitude. This will drive more efficient use of resources, improved & more timely communications to customers & stakeholders, and faster restoration times for all distribution system interruptions. Customization specific to customer and stakeholder communication will be available for outage and restoration notification via website, email, or automated phone call.

The planned OMS software is a new subsystem within the Survalent Windows SCADA package. It is designed to run on the SCADA host computers, with a user interface built into the WorldView operator interface. The OMS is therefore fully redundant along with the rest of the SCADA system. The training time for this particular OMS system is minimized because it is integrated directly into the existing SCADA graphical interface that the operator is already familiar with. This system will also capture outage information to drive more accurate and thorough outage reporting for further system analysis and optimization.

Timeline

The OMS is expected to be fully operational in 2013.

b) Communications Infrastructure Solutions

Current State

Oakville Hydro is completed a SCADA Communications Review with a third party to assess the SCADA telecommunications systems and alternatives for future technical field applications. This study supported continuation of a multi-technology approach to SCADA communications and the use of fibre-optic cables, licensed 400 MHz radio, and cellular Ethernet modems. One outcome of this report was the replacement of existing analogue licensed radio equipment in 2012 with digital radio infrastructure, and this was completed as planned.

Directional Plans

Oakville Hydro's SCADA communication scheme is now scalable to accommodate additional grid functionality as it develops.

c) Self Healing Grid

Current State

Oakville Hydro's long term vision is to develop a self healing distribution system grid that leverages automation systems for outage recovery, both centrally located in SCADA, and deployed using IEDs in the field. Distribution switchgear in Oakville has undergone an evolution from fully manually-operated equipment, to motorized and electrically - controllable equipment, and finally to the fully remote-controlled equipment used today that is equipped for automation.
Oakville Hydro's first Equipment Automation deployment is planned for 2013 in the form of padmount switches supplied from two sources that can automatically select the energized side. In existing SCADA-controlled padmount switchgear that is equipped for remote operation of both main incoming switches, the IED will be enabled to detect an outage and automatically shift the supply point over to the energized side. This will energize the local circuits supplied by this switchgear, and turn the power back on without any intervention from Oakville Hydro staff.

Directional Plans

Following the automation of between 2 and 5 isolated equipment locations in 2013, the next step will be Zone Automation. This will be achieved through the SCADA system with a software module for Fault Detection Isolation and Restoration (FDIR). This module will empower Oakville Hydro to set up automation schemes by feeder circuit in the areas that have the required density of automated equipment.

Moving forward, Oakville Hydro is well equipped to leverage its experience in SCADA operations, communication systems, IEDs, and control of field equipment to evaluate self healing grid technologies and develop the distribution system appropriately.

Timeline

Equipment Automation capability for between 2 and 5 padmount switches is planned to be in-place in 2013. Zone Automation (FDIR) capability is expected to be operational in 2014, with full self-healing grid materializing around 2020.

4. Adaptive Infrastructure

- **Equipment or system advancements that optimize business processes, in order to enhance resource effectiveness and/or generate cost efficiencies.**

a) GPS Tracking for Fleet Vehicles

Directional Plans

GPS tracking enables improved dispatching and shorter outage response times. The real-time location information simplifies dispatch decision-making, and identifies which crews are the closest to an outage or critical equipment.

This also drives increased visibility into field operations. The Control Room Operators are able to determine if crews are in the correct location for operating equipment, troubleshooting, line clearing, etc.

In addition, when there is an emergency in or near the vehicle, an emergency button can be pressed that will alert the Control Room Operator to dispatch the emergency services to their location.

Timeline

GPS tracking capability is currently available in Oakville Hydro's newly upgraded mobile radio system in fleet vehicles. Preliminary plans are underway to incorporate these GPS tags into our SCADA system – potentially in 2013.

b) Meter Remote Disconnect Capability

Directional Plans

Meter remote disconnect capability enables more efficient management of non-payment accounts and disconnects for move outs. Reconnect would be performed by the customer using their own television remote control device, which ensures that there is someone home during the reconnect, as a safety measure. Remote disconnect equipped meters will only be installed on a targeted segment of customers where the added cost is justified.

Timeline

This option is currently being developed in the industry and could potentially materialize in 2013-2014 timeframe.

c) Power System Analysis Tools

Directional Plans

Complimentary to the OMS system, a power system analysis tool (CYME) will be implemented to draw in the AMI consumption data and the GIS network model in order to deliver the capability for analysis of voltage drop, system losses, phase balancing, load flow, short circuit levels, protection coordination, arc flash studies, impact of distributed generation and associated connection impact assessments.

Timeline

The CYME software is expected to be operational in 2014.

d) ‘Harvester’ Solar Panels

Current State

In 2011, Oakville Hydro installed 16 ‘Harvester’ solar panels on poles throughout Oakville as a limited technology trial. This trial involved two locations with eight panels each, one at the South Service Road & Wyecroft, and the other at Joshua’s Creek Drive & North Service Road.

Directional Plans

Oakville Hydro plans to continue to evaluate the possibility of installing more ‘Harvester’ solar panels if appropriate benefits can be validated. The system is based on a single 220 - 280 watt solar panel, a Smart Energy Module with an inverter, two way wireless communications, sensors, digital meter, and a pole mounting system to attach to existing utility poles. The solar unit produces power directly to the secondary voltage lines with the following potential benefits:

- Power system voltage stabilization
- Addition fault locating capabilities for the Control Room
- Reduced line losses

5. Smart Grid Initiatives

- **Electric vehicles plus smart grid pilot projects that are funded by the MOE and/or approved by the OEB.**

a) dTechs Power Loss Monitoring - Smart Grid Fund Round 1 Approved Project

Directional Plans

Oakville Hydro is currently participating in the Ontario Smart Grid Fund demonstration pilot project in collaboration with dTechs for distribution system power loss monitoring and theft detection. This project involves the deployment of 225 units in 2013 to cover 25% of Oakville Hydro's customer base, with outage messages integrated into OMS. These metering units will supplement the fault indicators and AMI meter monitoring, and provide additional overall distribution system monitoring.

The dTechs MeterSuite is an advanced wireless metering system created to help utilities directly address grid management, line-loss reduction and power theft. The system will enable Oakville Hydro to increase its ability to detect, monitor and control technical and non-technical energy losses. The dTechs MeterSuite will find, immediately notify and direct Oakville Hydro to the location of atypical consumption. This includes power theft, unsafe high consumption and poor infrastructure areas (e.g. aged transformer equipment and poor distribution lines). The dTechs metering hardware installs quickly and seamlessly in the grid, measuring flow in real time at the most efficient location (medium voltage); that being the primary/tap line which delivers electricity to an average of 60 to 100 customers. MeterSuite is a one-time permanent deployment installed system-wide in the distribution grid that reconciles with existing smart meter (AMI) endpoint data. This monitoring allows for full system surveillance of power usage, regardless of technical or non-technical loss and the customer endpoint. These metering units will be powered by energy harvesting technology.

The dTechs system will be fully integrated within the IT infrastructure and will provide full usage information within the grid, assisting Oakville Hydro in locating loss areas. The theft detection aspect allows for the permanent termination of high loss endpoints. Coincidental termination of these high loss endpoints increases societal/public safety and reduces fire incidence. Furthermore, by fully monitoring the medium voltage lines, loss from aging infrastructure and proactive locating of poorly performing infrastructure will improve reliability and increase efficiency.

b) Demand Response Transformers - Smart Grid Fund Round 2 Application

Current State

Oakville Hydro is supporting Qurrent Solutions on their Smart Grid Fund round 2 application for "Demand Response Transformer". This demonstration project involves the replacement of approximately 10 utility distribution transformers with the Demand Response Transformer. This demonstration is intended to validate the efficiency outcomes for the Demand Response Transformer. The data received from this demonstration will be analyzed against existing transformer technology in order to compare two components, no-load losses and load factor which are associated with the millions of kilowatt-hours of energy lost annually in the generation and delivery of electricity. A report will then be completed to illustrate the potential savings associated with reduced energy loss including the cost of producing energy and the associated savings in greenhouse gas emissions from burning coal or other fossil fuels.

c) Energy Storage - Smart Grid Fund Round 2 Application

Current State

Oakville Hydro is supporting S&C on their Smart Grid Fund round 2 application for "Community Energy Storage for Microgrid and EV Charging". A number of other LDC's are supporting this application, specifically for Oakville Hydro, this pilot project will demonstrate the value of energy storage deployed in direct support for electric vehicle chargers. This project will also demonstrate how cyber secure wireless connections can be used to conserve electricity during the day by shifting the EV loads to either distributed generation or off-peak generation.

Directional Plans

Situated at the edge of the power grid or distribution system, either at the distribution transformer or at the customer premise, Community Energy Storage (CES) and Home Energy Storage (HES) systems are much smaller than utility-scale or bulk energy storage systems. Currently there are utilities, vendors, and governments testing CES and HES systems for the purposes of smoothing peaks in electricity demand, enabling voltage support and frequency regulation. If EV adoption is high, energy storage may be an important partner technology to lessen impacts on the distribution system. Although CES and HES are still further into the future in terms of commercial deployment, Oakville Hydro plans to monitor and study the progress of this technology.

d) Electric Vehicles (EVs)

i) Member and Active Participant of "Plug'n Drive" and "Charge My Car"

Current State

Plug'n Drive Ontario is a not-for-profit coalition engaging in activities that will accelerate the adoption of electric vehicles and maximize their environmental and economic benefits for consumers and businesses in Ontario. Oakville Hydro is one of several GTA and GHA area LDC members in this coalition. The key priorities are education, awareness, research and infrastructure. The goal is to create a one-stop shop for information on EVs in Ontario to enable easier customer EV adoption. Road shows will be conducted to educate and excite consumers on the benefits of EVs. The group will engage in research that will help fill the gaps needed to advance EV deployment and influence consumer behaviour, as well as promote the development of EV infrastructure. Web development is currently underway to standardize approach and provide assistance to consumers in such areas as power assessments and residential EV charger installations.

ii) Strategic Partnerships

Directional Plans

Oakville Hydro plans to coordinate and align with the Town of Oakville's Environmental Strategic Plan. The current Town Plan focuses primarily on fleet opportunities but is intended to expand to community charging facilities. Being an active partner, will further promote EVs in the community, and contribute to the success of this Environmental Strategic Plan.

In addition, Oakville Hydro is an active player in the GridSmartCity consortium that is currently exploring collaborative opportunities in smart grid technologies and operational efficiency ventures.

It will also be worthwhile to partner with other EV interested parties. Partnering with Metrolinx, and exploring opportunities at GO stations in Oakville, could provide EV solutions to commuters – this promotes Oakville Hydro in the community and could add load to the distribution system.

Developing relationships with dealerships and installers will be helpful in assisting customers, and promoting EVs in the community.

iii) Staff Training

Directional Plans

In order for Oakville Hydro to be successful and ready for the EV evolution, training in various areas will be important. Customer-facing staff will require training about EVs and how to handle customer requests. Distribution planners and engineers will need to know about the possible impacts on the distribution system, and how to plan for deployment. Line & Control staff will require training on field operations, monitoring and control.

iv) Promotion of EVs in the Community

Current State

In 2013, Oakville Hydro partnered with Tim Horton's to install vehicle charging stations at one of its locations in the Town of Oakville. Oakville Hydro will continue to monitor the situation and work towards enabling their roll out through collaborative ventures. In the 2013 customer satisfaction survey, the number of customers that were "very interested" in purchasing an electric vehicle declined to 7% from 10% in 2011.

Directional Plans

Promotion of EVs can be carried out in several ways including advertising with community partners, active participation in Plug'n Drive and Charge My Car, aligning with the Town of Oakville and EV promotion on the website. For EVs to be successful in Oakville, Oakville Hydro should play an active role in the community and with customers.

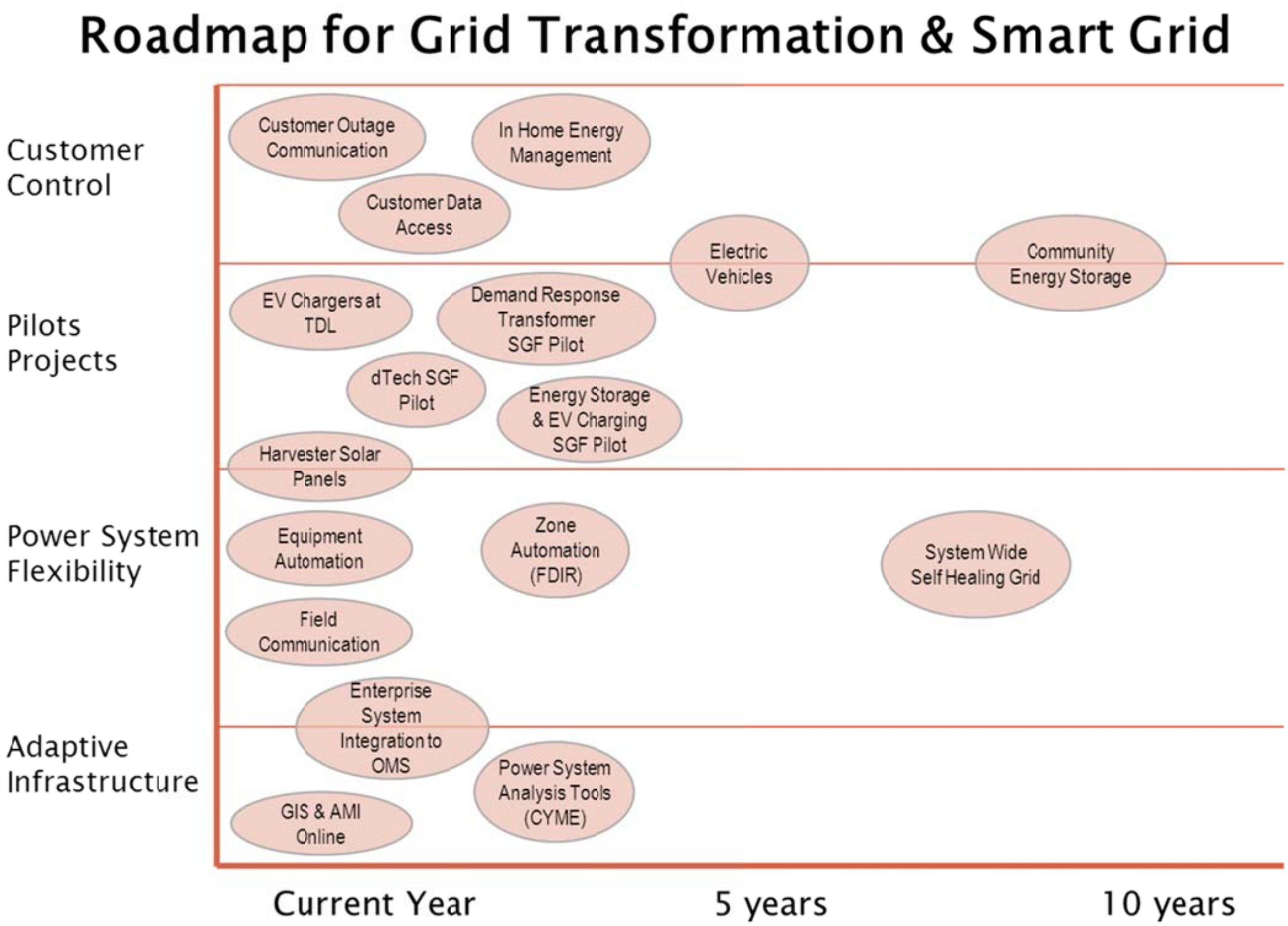
Knowing when and where EV chargers are active is important in understanding their impact on the distribution system. Through participation with Plug'n Drive and Charge My Car, and our own standards and promotions, smart chargers should be recommended that can send an alert when an EV is plugged in. This will enable Oakville Hydro to monitor and possibly control chargers, to the benefit of the distribution system.

v) Integration to Existing Systems

Directional Plans

For network planning purposes it is important to know where EV chargers are installed. Oakville Hydro will utilize the existing GIS system to track the location of customer- owned EVs and established community charging stations. This will be necessary to monitor the locations and study the impact of EVs on the distribution system.
Oakville Hydro's CIS (Customer Information System) should be enabled to track customers that have EVs and charging stations. With smart meter data already available, this would provide not only day-to-day customer information, but excellent planning data and tools – which will be essential if EV adoption is high.

It will also be important to conduct system studies in different areas of the distribution system to evaluate the impact of EVs. For example, in certain areas of the underground system, EVs will likely have little impact on the system, whereas in older overhead areas, the system could be constrained. It will be important to know which areas will have capacity issues, in order to properly plan for capital upgrades, should EVs materialize.


Roadmap for Grid Transformation & Smart Grid
Customer Control
Pilots Projects
Power System Flexibility
Adaptive Infrastructure
Customer Outage Communication
In Home Energy Management
Customer Data Access
Electric Vehicles
Community Energy Storage
EV Chargers at TDL
Demand Response Transformer SGF Pilot
dTech SGF Pilot
Energy Storage & EV Charging SGF Pilot
Harvester Solar Panels
Equipment Automation
Zone Automation (FDIR)
System Wide Self Healing Grid
Field Communication
Enterprise System Integration to OMS
Power System Analysis Tools (CYME)
GIS & AMI Online
Current Year
5 years
10 years

Appendix 6

Information Technology Strategy

Information Technology Strategic Plan
2013

Introduction

Information Technology plays an important role in enabling the entire business to operate. The Information Technology (IT) department is responsible for the technology services that facilitate the business to seamlessly organize, analyze and improve the flow of information necessary for the offering of services to its customers. Telecommunications, automated data processing, databases, the Internet, management information systems, and related information, equipment, goods, and services all encompass IT areas of service.

Information Technology will be a key enabler for Oakville Hydro Electricity Distribution Inc. (Oakville Hydro) in meeting its goal of value for ratepayers. In support of effective planning of our future technology investments, Oakville Hydro's Information Technology department uses the overall Oakville Hydro Strategic imperatives as a guide in making operational decisions:

- profit - by reducing costs through productivity improvement and improved business process
- service - by enabling customer self-service and web-based and lower cost interactions, and providing internal customer service to other operational areas of the business
- people - by enhancing collaboration and increasing productivity and to use technology to assist in delivering a safe work environment
- community - by proving a key communications vehicle, the public web site and customer access to important information in the community and facilitating the transfer of information in order to service the community and customers

Over the last 4 years, the demand for more IT services has increased –new projects, applications, system maintenance and rethinking/replacing technologies, placing a heavier reliance on systems as more and more services become driven and dependent on technology. A good example of this change is the significant information technology component associated with Smart Meters. The IT department understands those requirements and is willing and motivated to meet current and future projects along with the everyday running of "normal" business needs.

Without clear direction the network infrastructure can become a conglomerate of pieces added to the systems as the needs arise, adding cost and inefficiencies to the IT systems. This method decreases the level of service to the business. With focus on four main areas of technology shown in figure 1, the infrastructure and consequently the health of the foundation systems can support the demands of the industry and provide the level of service that Oakville Hydro needs to move ahead with the strategies of the organization's overall business plan.

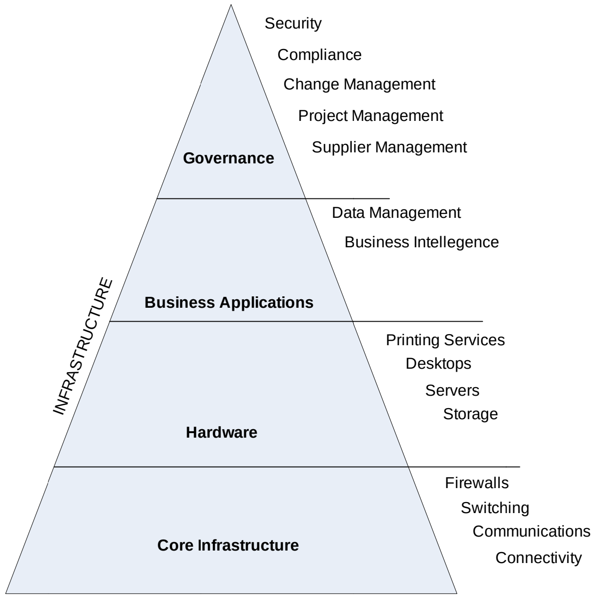


Figure 1

A solid core infrastructure is the key to successful implementation of new technologies, and is included in our asset management plan. Standards in equipment and strong change management procedures support the ongoing maintenance of the systems. Up to date hardware and software provide a strong and secure environment to new and existing projects and programs. Hardware needs to be maintained and configured properly and applications need to be upgraded annually to take advantage of new features and security offered by vendors. A three to five year asset management plan ensures the desktops, servers and security infrastructure is maintained up to date without excessive maintenance costs and with the necessary processing capability to meet the increasing demand by users in order to service the customers, all at a reasonable cost.

Governance is the protection afforded to IT systems and data in order to preserve their availability, integrity, and confidentiality.

Resources in the IT team are fully engaged in the planning process and every member will contribute to the overall success of the organization. External supplier management is in place to review all current and future contracts to ensure the full value of acquired systems and services is available for the Company and will be a template when requesting new services.

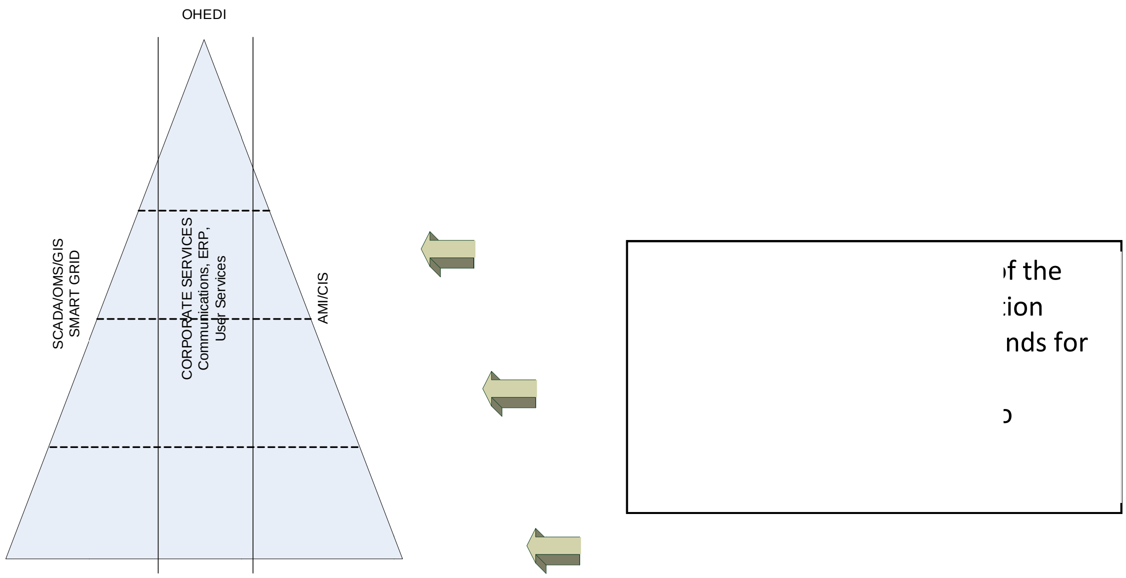


Figure 2

IT Business Objectives

Infrastructure Stabilization

The network, data center and applications are becoming increasingly complex and business-critical. The health of these systems relies on effective monitoring and constant measurement of capacity and performance of the infrastructure within which the hardware operate.

Over the past few years there have been dramatic changes in the electrical industry operation, such as Smart Meters, that necessitate a review of the overall consolidated infrastructure plan. With a focus to stabilize the infrastructure we can deliver high-quality, reliable, information technology and communication services to keep up to date with the changing landscape in the industry.

Performance and system reliability will improve with a stable, adaptive infrastructure that is a high-performance, low-latency, segmented networking environment to address rapidly growing demands of data and analytics. This stabilization is underway in 2013 and will be a foundation of the entire infrastructure going forward.

Mobility and Mobile Device

In a news release on Oct 23, 2012, Gartner Inc. predicted that by 2013 mobile phones will overtake PC's as the most common Web access device and by 2015 over 80% will be smartphones; with only 20% of those in the windows market.

The customer demands for more mobile device applications will drive Oakville Hydro to provide its data to the smartphone clients. This trend will have its own challenges in the secure provisions of data and complex application development for the devices. As customers begin making these demands, application providers will start to move in this market there will need to be adaptability until a customer limit to the design of applications for specific devices comes forth. IT will need to have the capability to adapt to the changes in demands for information in order to deliver it to customers.

Internally we will continue the expansion, upgrade and integration of Wi-Fi, cellular and radio technologies to improve mobile device access and security across the organization. This impacts the infrastructure of the organization in areas of connectivity, hardware, security procedures and practices and their impact on specific business applications. As with all mobile access, privacy is a significant concern and is addressed in our company's privacy policies.

Data Management and Analytics

Our current data management is a "physical" linear approach that demands high server hardware implementation. Increases in data volume with different variety, velocity and complexity will force us to change traditional approaches of server based services to more of a data warehouse of multiple systems with data services and metadata providing a "logical" enterprise data warehouse.

Analytics delivered to the end user will enable more decision flexibility. Business Intelligence will include, at the desk dynamic analytics to better respond to the changing landscape of data.

Integration services are provided with the current set of applications which helps with the integrity of data and improved efficiency. As data integrity expands, we will increase the integration activities between systems to improve the efficiency of analytics. Data warehousing requires a robust infrastructure and specialized hardware for the efficient storage of the data.

Systems Security Goals

Cyber Security demands will increase as more data is made available to the public and there is the growth in the mobility of devices. Controls are in place for escalating threats and new vulnerabilities; however, as technology constantly changes we continue to redefine the framework for achieving our delivery systems Cyber Security. This again highlights the need for adaptability and flexibility as technology changes.

Governance is a critical component overseeing infrastructure, hardware and business applications. Control of access at the desktop, laptop and mobile device level ensures data is stored ensuring data integrity, maintenance of privacy. Change management maintains the systems at its highest level of security and best functionality. Security audits are conducted to provide regular health checks and ensure security procedures as defined are put into practice.

We will expand the current process to include incident and event management. Effective response to security breaches, once identified, will ensure a maturing program of access control. Expanded training and education will increase the network and data protection. IT will work closely with the Regulatory group, specifically with regards to privacy of information.

Collaboration Services

Oakville Hydro has deployed a standards-based enterprise collaboration service, integrating e-mail, calendars, phones and document sharing. Expansion of these services will include instant messaging, archives, mobile access and records management. These new solutions will provide a foundation for new collaboration practices, regulatory compliance and enhanced productivity.

Oakville Hydro has a web site that provides information to the community and our customers. We will continue to expand and provide more visibility and interaction with our community by increasing our services provided on the internet. Incorporating social media collaboration like Twitter, Facebook, LinkedIn and others, will help meet the demands of our stakeholders to provide information on outage management, account information and service offerings. The integration of systems will be critical in efficiently and effectively communicating outages and system reliability with our customers, while maintaining overall cyber security and privacy.

Oakville Hydro will work with other LDCs and the Town of Oakville to support some of the corporate services that are common to all affiliates. This collaboration of efforts will help to reduce the overall operating costs while providing a strong secure environment for our services.

Learning Services

Our goal is to improve the experience of employee learning. Employee involvement in the IT process involves understanding the technology and how it can help the daily work load. Expanded training will provide a bridge to the opportunities that exist in the area of technology and how we can use this to make more informed business decisions. E-Learning applications will provide ongoing access to learning material after the classroom also giving employees the option of how they want to learn.

Information technology staff must maintain expertise in industry solutions as it is critical to providing reliable services to the community at Oakville Hydro and the Town of Oakville.

Disaster Recovery Planning

Oakville Hydro has a functional Disaster Recovery Plan that outlines the critical services provided by Oakville Hydro to its customers and employees. IT will support and maintain all aspects of the disaster recovery and continue to build the Business Continuity Plan which will be tested and integrated into the OHEDI Emergency Operations Plan. This Business Continuity Plan will integrate with the Town of Oakville's infrastructure and network.

Oakville Hydro has hosted the Disaster Recovery Server for Milton Hydro for a number of years and will explore a reciprocal arrangement. The IT department will look at this and other arrangements to ensure cost efficient delivery of IT services for the business and, if possible, mitigation of costs through cost sharing service agreements.

Risk Management

- Active management of the system
    - Changes in IT management have provided the proper guidance in maintaining the IT strategy

- Contract and supplier management
    - Maintain contracts supplier agreements
    - Agreements with clearly define responsibilities

- Asset management to maintain aging equipment with standard system images.
    - Manage the stability with careful evolutionary improvements rather than revolutionary change with full consideration of the need for adaptability for future unknown changes to systems and system requirements

- Security of the IT infrastructure through governance programs that takes into account SOX and NERC compliance principles

- Data management has multiple application impacts to critical areas such as Asset Management, Smart metering, Outage management, financial planning and regulatory compliance.

- Development and project implementation processes, including developing templates and procedures
    - Project support to help reduce the risk of scope, time, and cost management in projects

At a corporate level there continues to be a strong focus on Cyber Security and Privacy which are being addressed through the use of internal audits of firewall security, change management and ultimately with an external audit performed. Changes in governance of user access, system changes and application access is increasing, thereby reducing the risk. Firewall systems are continuously updated and re-configured to improve protection and privacy remains a priority with considerable effort to liaise with the Regulatory while still moving projects forward.

Information Technology goals are to establish a "continuous improvement" culture to incrementally build on a stable network infrastructure to meet the changing needs of the industry.

Appendix 7

Material Capital Project Templates

Summary 2014 Capital Projects over Materiality Threshold

Project #	Description	System Type
14-64A1	SCADA Enhancements in Loadflow, Contingency Analysis, FDIR	System Service
16-G2	27.6kV Air insulated switchgear upgrades to G&W	System Renewal
16-U1	Gang-Op Switch Replacement Program	System Renewal
05-P2	Power Transformer Replacement Program	System Renewal
05-Q2	Victoria MS Low Voltage Breaker Replacement Program	System Renewal
46-A	Replace Overhead Assets on John Street	System Renewal
46-B	Replace Overhead Assets on Queen Mary, Bond and Chisholm	System Renewal
46-C	Replace Overhead Assets on Robinson St.	System Renewal
45-A	Vault Transformer Replacements	System Renewal
45-D	Poletran Removals and Replace U/G Assets Various Locations	System Renewal
45-Q	Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion	System Renewal
45-X	Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln	System Renewal
42-B	Live front Padmount Transformer Replacements	System Renewal
44-H	27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403	System Access
14-50C	New Development Investment	System Access
14-54	New General Services	System Access
14-61	Distribution Meters	System Access
15-E	North Service Rd Widening, 8th Line to Iroquois Shore Rd	System Access
15-I	Road Widening TBD	System Access
14-62	2014 Fleet	General Plant
14-64D	ERP - GP & Business Intelligence	General Plant
14-64F	IT Infrastructure	General Plant
LSHOLD	HVAC upgrade - 5 year replacement program	General Plant

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN
Engineering

GENERAL

Project Number:	14-64A1
Project Name:	SCADA Enhancements in Loadflow, Contingency Analysis, FDIR
Project Category:	Administration - IT
System Type	System Service
Customer Attachments/Load:	
Project Manager:	Jeff Mocha
Start Date:	January 1, 2014
In Service Date:	October 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$300,000	$300,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$300,000	$300,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$300,000	$0	$0	$0

Risks to Completion and Risk Mitigation:

The current SCADA system has been in service for several years, the proposed enhancements are a functional upgrade to this system. The proposed software enhancements are in service at other utility companies, and are mature products. A detailed project plan will be developed with a defined scope of work. We plan to work closely with the system provider to integrate into our existing SCADA system on time and on budget.

Comparative Information on Equivalent Historical Projects (if any):

Successfully managed development and implementation of Outage Management System functional upgrade with same vendor in 2013

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

The following functional upgrades will be added to the existing SCADA system:
Loadflow will provide the Control Room Operators with an analysis tool to simulate the impact of system loading levels to drive the right solutions.
Contingency Analysis is complimentary to Loadflow, and will provide the Control Room Operators with a report that highlights critical components in the distribution system, allowing the Operator to reconfigure the system as necessary.
Fault Detection Isolation Restoration (FDIR) is also complimentary to Loadflow, and is an element of grid transformation that builds a level of automation into the SCADA system. Existing field sensors and controllable switches are leveraged, and the SCADA system is able to take action without Operator intervention to begin system restoral following an outage.

Project #: 14-64A1
Project Name: SCADA Enhancements in Loadflow, Contingency Analysis, FDIR

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
Process improvements in the Control Room that drive optimized system configuration and improved outage restoral.

Priority and Reasons for Priority:
This project is ranked as a high priority because it will mitigate existing operational risks associated with feeder loading and equipment operation.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Oakville Hydro's SCADA system is wholly dedicated to the Oakville Hydro distribution system. These enhancements provide system tools that are not available in any other format without removing the entire SCADA system and investing in a full system change out. This alternative would be very costly and disruptive to Control Room Operations.
The addition of these functions would shorten the restoration time following unplanned outages. Also, optimized load flow would provide the Control Room Operators with the information needed to prevent stressing system equipment when the system is operated out of normal configuration.

2. Safety

The Loadflow information provided to Operators will be communicated to field staff to drive proper selection of switching equipment, driving a safety improvement for field staff.

3. Cyber-Security, Privacy

All SCADA traffic is transmitted from our SCADA Masters of which 2 machines are at our head office and the 3rd is offsite. A secure 400MHz radio network is used for remote motorized switches and fault indicators. There is a 1 Gbps dark fiber network interconnecting all our substations.

4. Co-ordination, Interoperability

n/a

5. Economic Development

The SCADA vendor is based out of Mississauga, this investment will support local economic development

6. Environmental Benefits

n/a

Project #: 14-64A1
Project Name: SCADA Enhancements in Loadflow, Contingency Analysis, FDIR
System Type: *System Service*

CATEGORY SPECIFIC REQUIREMENTS

Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable:

The Loadflow and Contingency Analysis functional improvements will prevent equipment stress, maintaining asset health and avoiding premature equipment failure & replacement.

Regional Electricity Infrastructure Requirements which Affected Project , if applicable:

n/a

Description of Incorporation of Advanced Technology, if applicable:

The proposed enhancements will provide additional tools to the Control Room Operators including detailed system load levels, critical equipment impacting system operations, and automatic restoration following an unplanned outage.

Identify any reliability, efficiency, safety or coordination benefits:

Reliability is improved with automated restoration capabilities built into the SCADA system. The Loadflow information provided to Operators will be communicated to field staff to drive proper selection of switching equipment, driving a safety improvement for field staff.

Factors Affecting Timing/Priority:

The proposed enhancements were originally planned for 2013, but development and implementation of the Outage Management System (OMS) lasted into 2014. The first stage of the OMS project required export of GIS network into SCADA, and there were a number of technical challenges that were unforeseen and required resolution. The proposed enhancements require this same network before they can be implemented.

Analysis of Project Benefits and Costs with Alternative Comparison, including "Do-Nothing" Alternative (include qualitative factors if applicable):

Without FDIR, remote restoration would continue to be done manually by Control Room Operators. Without Contingency Analysis, the distribution system will continue to be at risk when switched out of normal configuration.

Project #: 14-64A1
Project Name: SCADA Enhancements in Loadflow, Contingency Analysis, FDIR

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number: 16-G2
Project Name: 27.6kV Air insulated switchgear upgrades to G&W
Project Category: Alterations and Improvements for Load Transfer and System Security
System Type System Renewal
Customer Attachments/Load:
Project Manager: Daniela Motoc

Start Date: October 1, 2013
In Service Date: May 15, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$465,000	$379,340
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$465,000	$379,340
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$379,340	$0	$0

Risks to Completion and Risk Mitigation:
This equipment has a very long leadtime, but this will be mitigated by developing the project plan and placing the equipment order in 2013. At the time of installation, there can be unforeseen conditions such as cable length, cable condition, etc.

Comparative Information on Equivalent Historical Projects (if any):
Replacements similar to this proposed replacement have been executed a number of times over the last few years. The proposed replacements use standard materials and field crews have the necessary experience.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:
This budget represents the risk, value and cost for the program to complete replacement of 27.6kV air insulated switchgear with new gas insulated switchgear with remote control back to the control room. The existing air insulated switchgear is subject to accelerated aging due to adverse weather conditions, road salt, etc. The gas insulated switchgear have a sealed tank compartment preventing the accelerated aging. This budget represents year two of the program. This project will cover all costs to convert the switchgears and supply new AC service to the locations if required. Proposed for conversion are SC208 on Voyager Dr, south of Dundas St, SC132 on River Glen Blvd at Harman Gate, and SC100 on Heritage Way, west of Goldsmith.

Project #: 16-G2
Project Name: 27.6kV Air insulated switchgear upgrades to G&W

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The existing assets that are proposed for replacement are reaching end of life and represent a reliability risk to our system.

Priority and Reasons for Priority:
The proposed locations represent a high risk to the distribution system due to the potential to affect large customer groups in the event of failure. Each of these switchgear locations have local circuits directly connected to radially supply customers.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Realize savings of switchgear dry ice cleaning. Air insulated equipment is prone to premature failure and would warrant emergency replacements causing the requirement of additional, non budgeted funds. Crews are needed to be dispatched to mitigate this emergency causing delays in other work. Failed air insulated equipment causes feeder lockout. Crews would have to identify the issue of the failed equipment, and perform switching. Depending on location of failed equipment, some customers could be off up to four hours until the fix was performed.

2. Safety
Switchgear in a degraded, reaching end of life condition can be hazards for electrical flashover due to a build up of contamination on the insulators within the switchgear cubical. New switchgear would contain no contamination, and would make use of Cycloaliphatic Epoxy Resin system which provide maximum resistance to power arcs.

3. Cyber-Security, Privacy
N/A

4. Co-ordination, Interoperability
The control system supplied with the new equipment uses industry standard, substation style, controller products that use communication protocols that are standard in the utility industry. At a later date these can be integrated into an automated restoration scheme.

5. Economic Development
N/A

6. Environmental Benefits
N/A

Project #: 16-G2
Project Name: 27.6kV Air insulated switchgear upgrades to G&W
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Asset conditions are listed as "Fair" with equipment at end of life. These assets have a poor performance record past their typical useful lives.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Number of customers affected range between 5,000 to 9,000 customers. Primarily residential customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the assets fails. We could expect to see auto-recloses due to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 90-240 minute outage to allow for sectionalizing, approximately 450,000-2,160,000 customer minutes. High risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

Medium to High with the length of outage and number of customers

Factors Affecting Project Timing, if any:

Substantial amount of equipment lead-time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Increase maintenance costs involved due to cleaning required for the existing switchgears, new style switchgear proposed for installation is hermetically sealed and gas filled, so it does not require cleaning.

Reliability and Safety Factors:

Newer switchgear is more reliable due to construction materials, hermetically sealed, and gas filled. Deadfront construction switchgear reduces the potential for injury due to flashovers.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective, this is a like for like replacement, but the proposed equipment is technologically enhanced compared to the existing equipment. The new equipment is hermetically sealed and gas filled to reduce the required maintenance. The new equipment also has two remotely controllable ways compared to the existing equipment which may not even have remote control option.

Project #: 16-G2
Project Name: 27.6kV Air insulated switchgear upgrades to G&W

O T H E R I N F O R M A T I O N

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number: 16-U1
Project Name: Gang-Op Switch Replacement Program
Project Category: Alterations and Improvements for Load Transfer and System Security
System Type System Renewal
Customer Attachments/Load:
Project Manager: Daniela Motoc

Start Date: March 1, 2013
In Service Date: May 21, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$361,000	$267,139
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$361,000	$267,139
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$267,139	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long leadtime, but this will be mitigated by developing the project plan and placing the equipment order in 2013. At the time of installation, there can be unforeseen conditions such as pole height.

Comparative Information on Equivalent Historical Projects (if any):

Similar projects since 2006 providing approximate costs for this work.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the program to replace 27.6kV Vacuum gang operated switches in the distribution system. This is year one of the program, and will cover the cost to replace five switch locations with new SCADAMate loadbreak switches. The proposed locations are S3111-V at 1400 North Service Road West between Third and Fourth Line; S1015-V on Burloak Rd, two poles south of Rebecca Street; S3074-V on Third Line at the North Service Road (North East corner); S2049-V on Speers Rd, West of Speers MS; S2063-V on Bronte Rd, 3 poles south of South Service Rd; These switches tend to fail without warning, and there is no maintenance that can be performed in order to keep them in working order. In the case they fail, we do not have any spare parts to have them fixed, and they must be replaced with newer style remote operated switches.

Project #: 16-U1
Project Name: Gang-Op Switch Replacement Program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
Support of Organizational Strategy - Service, by balancing asset management in conjunction with safety, reliability and cost. Reducing the risk to service quality, company image due to degrading service quality, public and employee safety.

Priority and Reasons for Priority:
High Risk, High Probability of failure. Failures can affect multiple TS feeders. In the case these assets fail prematurely, in order to ensure the system is reliable, funds need to be made available to replace the assets regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Vacuum switches are prone to premature failure and would warrant emergency replacements causing the requirement of additional, non budgeted funds. Crews are needed to be dispatched to mitigate this emergency causing delays in other work. Failed vacuum switches can cause multiple feeder lockouts. Crews would have to identify the issue of the failed equipment, and perform switching. Depending on location of failed equipment, some customers could be off up to four hours until the fix was performed.

2. Safety

Vacuum switches in a degraded, near end of life condition can be hazards for electrical flashovers or explosions. There has been recorded history of these switches exploding, and in one case causing a fire.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 16-U1
Project Name: Gang-Op Switch Replacement Program
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Conditions range from Poor to Very Poor per Health Index. Typical life cycle is 25 years. Assets currently over that life.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

7243 to 13000 customers affected by these assets. Mostly residential customers with some commercial/industrial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see auto-recloses due to flashove

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

Five gang operated switches are proposed to be replaced each year over the forecast period. The vacuum switches are the oldest and most risky gang operated switch in Oakville Hydro's distribution system and will be replaced first, followed by the motor operated load break switches, then load break switches.

Consequences for O&M System Costs Including Implications of Not Implementing:

Expected increase of patrols due to auto-recloses caused by flashovers in these assets causing an increase in O&M system cost. Remote operation failure can cause additional switching times as crews would have to manually access the switching point.

Reliability and Safety Factors:

Newer gang operated switches are more reliable due to construction materials and methods. The switches shall utilize an integrated switch operator having no exposed moving parts between the switch and any other device. The interrupters and the stored-energy operating mechanism shall be maintenance-free. The switch shall have an integral visible-break disconnect device operable by means of a hookstick. Maintenance-free wiping contacts to prevent operational difficulties arising from corrosion or frost. Self-lubricating, maintenance-free bearings.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 16-U1
Project Name: Gang-Op Switch Replacement Program

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number: 05-P2
Project Name: Power Transformer Replacement Program
Project Category: Substations
System Type System Renewal
Customer Attachments/Load:
Project Manager: Scott Carpenter

Start Date:
In Service Date: October 22, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$300,150	$268,190
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$300,150	$268,190
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$118,190	$150,000	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long leadtime, but this will be mitigated by developing the project plan and placing the equipment order in Q4 2013. At the time of installation, there can be site specific restrictions such as existing transformer foundations that need to be accommodated.

Comparative Information on Equivalent Historical Projects (if any):
In the last 5 years we have replaced 3 Municipal Substation power transformers of similar size on schedule and on budget.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:
This budget represents the risk, value and cost for completion of the yearly program to replace power transformers in the distribution system. It is proposed to replace one power transformer per year in order to manage capital spending levels in the future. If Oakville Hydro does not start replacing these transformers pro-actively, they encounter situations where more than one of these expensive long lead transformers will be required to be replaced within the same year, putting the system at risk and driving capital costs higher than expected. It is proposed to replace the power transformer at Woodhaven Municipal Substation which is the oldest power transformer in our distribution system and has been in service since 1957.

Project #: 05-P2
Project Name: Power Transformer Replacement Program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is to avoid the risks associated with the failure of Municipal Substation power transformers. Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a transformer failure all of these customers would need to be transferred to other substations, which would be challenging to achieve during the summer peak load season and would require extensive manual field operation and coordination.

Priority and Reasons for Priority:
High Risk, High Probability. In the case one of these assets fail we could expect multiple MS feeders to be affected, and it will place our system at risk as the existing feeders will need to be fed from adjacent stations causing strain and inflexibility on the system. In the case this asset fails prematurely, in order to ensure the system is reliable, funds would need to be made available to replace the asset regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Without a proactive replacement program for these transformers we could expect to spend over $300,000 to replace a failed unit after an unexpected failure. With no capital budgets set for replacements this would cause a large deferral of a set project. There is potential for large extensive outages until such time as the transformer is replaced, or the load on the feeders can be properly distributed to adjacent feeders. We could also expect longer outages during emergency situations due to the inflexibility of the system with a station out for an extended period of time.

2. Safety

N/A

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 05-P2
Project Name: Power Transformer Replacement Program
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

<u>Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:</u>

1. Condition of Asset vs. Typical Life Cycle and Performance Record

This asset is 56 years old, and has been noted to have a poor oil quality. Typical lifecycle is 45 years.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Approximately 715 customers are serviced from this transformer, mostly residential.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We can expect an approximate 120 to 300 minute outage to allow for sectionalizing, approximately 85,800 to 214,500 customer minutes. Medium-High Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

High

<u>Factors Affecting Project Timing, if any:</u>

These assets are proposed to be replaced once per year over the forecast period. There are 36 of these assets in the system, at an investment of one per year every unit is proposed to be replaced after TUL has passed. High priority vs. other projects.

<u>Consequences for O&M System Costs Including Implications of Not Implementing:</u>

We would expect to require oil testing on a more frequent basis depending on how quickly the oil condition deteriorates.

<u>Reliability and Safety Factors:</u>

Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a transformer failure all of these customers would need to be transferred to other substations, which would be challenging to achieve during the summer peak load season and would require extensive manual field operation and coordination.

<u>Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):</u>

N/A

Project #: 05-P2
Project Name: Power Transformer Replacement Program

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program
Project Category: Substations
System Type System Renewal
Customer Attachments/Load:
Project Manager: Scott Carpenter

Start Date:
In Service Date: October 22, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$635,400	$547,715
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$635,400	$547,715
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$147,715	$400,000	$0	$0

Risks to Completion and Risk Mitigation:

This equipment has a very long lead-time, but this will be mitigated by developing the project plan and placing the equipment order in Q4 2013. At the time of installation, there can be site specific restrictions such as existing footprint requirements for the breakers to accommodate cable entry.

Comparative Information on Equivalent Historical Projects (if any):

In the last 5 years we have replaced 4 sets of breaker equipment in Municipal Substations of similar size on schedule and on budget.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the yearly program to replace a lineup of low voltage breakers in the distribution system. It is proposed to replace one breaker lineup per year in order to manage capital spending levels in the future. If Oakville Hydro does not start replacing these breakers pro-actively, they encounter situations where more than one of these expensive long lead lineups will be required to be replaced within the same year, putting the system at risk and driving capital costs higher than expected. It is proposed to replace the breaker lineup at Victoria MS, which is the oldest metal clad breaker lineup in the distribution system and has been in service since 1973.

Project #: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is to avoid the risks associated with the failure of Municipal Substation breaker equipment. Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a switchgear failure all of these customers may need to be transferred to other substations, which would be challenging to achieve during the summer peak load season, and would require extensive manual field operation and coordination.

Priority and Reasons for Priority:
High Risk, High Probability. In the case one of these assets fail we could expect multiple MS feeders to be affected, and it will place our system at risk as the existing feeders will need to be fed from adjacent stations causing strain and inflexibility on the system. In the case this asset fails prematurely, in order to ensure the system is reliable, funds would need to be made available to replace the asset regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Without a proactive replacement program for these breaker lineups we could expect to spend over $400,000 to replace a failed lineup after an unexpected failure. With no capital budgets set for replacements this would cause a large deferral of a set project. In the case of failure, we could have large extensive outages until such time as the lineup is replaced, or the load on the feeders can be properly distributed to adjacent feeders. We could also expect longer outages during emergency situations due to the inflexibility of the system with a station out for an extended period of time.

2. Safety

The existing equipment is contained within a fabricated metal outdoor enclosure rather than a brick building. The metal enclosure and the switchgear equipment is all past end of life, and will be replaced as one unit. The aging enclosure presents a risk of water entry to the switchgear, which is a safety hazard associated with operation during poor weather conditions. The physical breakers have a number of critical mechanical components that are subject to wear & tear, and present a misoperation risk when they are operated past useful life.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

This asset has exceeded its typical useful life of 25 years.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

826 Customers serviced from this breaker equipment, mostly commercial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see feeder circuit interruptions due to issues with equipment operation without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 120 to 300 minute outage to allow for sectionalizing, approximately 99,120 to 247,800 customer minutes. Medium-High Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention. Medium Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

These assets are proposed to be replaced once per year over the forecast period. Currently 19 of these assets in the system, at an investment of one per year every unit is proposed to be replaced after TUL has passed. High priority vs. other projects.

Consequences for O&M System Costs Including Implications of Not Implementing:

N/A

Reliability and Safety Factors:

Our Municipal Substations supply anywhere from 500 to 2000 customers, and in the event of a switchgear failure all of these customers may need to be transferred to other substations, which would be challenging to achieve during the summer peak load season, and would require extensive manual field operation and coordination.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 05-Q2
Project Name: Victoria MS Low Voltage Breaker Replacement Program

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN
Engineering

G E N E R A L

Project Number:	46-A
Project Name:	Replace Overhead Assets on John Street
Project Category:	Rebuild Overhead Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	May 1, 2013
In Service Date:	June 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$310,000	$207,270
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$310,000	$207,270
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$155,453	$51,818	$0	$0

Risks to Completion and Risk Mitigation:
Delays may occur due to unforeseen conditions of existing old duct infrastructure not being useable to replace the existing cable. The existing cable might be too short to be transferred to the new poles or the existing vault structure might be found in poor condition and may require replacement.

Comparative Information on Equivalent Historical Projects (if any):
Over the last five years projects to replace similar equipment have been executed with costs between $50,000 to $300,000.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:
This budget represents the risk, value and cost to replace the overhead assets located on John Street between Brock St and Forsythe St. Primary and secondary distribution system assets at this location were found in poor condition during the 2010 overhead patrol reports and should be replaced in order to mitigate the risk of the assets failing along this stretch of road. Also any existing underground dip cables of insufficient length should be replaced. Due to lack of fusing some local feeders are directly connected to the express feeders in this area.

Project #: 46-A
Project Name: Replace Overhead Assets on John Street

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main driver - Balancing asset management in conjunction with safety, reliability and cost. Reducing risk due to degrading service quality by installing new, more reliable assets, as well as following current installation standards and specifications.

Priority and Reasons for Priority: High risk, high probability. Failure can affect many customers due to the existing radial feed system configuration. In case some of the assets fails prematurely, to restore power in this area funds will need to be available to replace assets regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These assets are servicing mostly commercial zoned properties and some residential services. We could expect to have multiple customers off at a time. Some parts are directly connected to our express feeders, so problems would affect the whole feeder. If one of these assets fails, we would need to replace it immediately. If the aging assets are not replaced possible failures could cause faults and affect the entire feeder due to direct connections. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace. The load on the feeder could be off up to 4 hours until the issue is resolved. Due to the age of the assets we could expect a pole with a transformer to fall over which could cause the insulating oil to spill on a customers property. The top of most of these poles are rotten and if relocation of overhead conductor is required to eliminate a public safety hazard, then clearances are a significant issue. This area is located in a high vegetation level area and current overheads primary conductor insulation is in very poor condition, and there is risk of a fire hazard during periods of high winds and storm conditions. During design all pole loading, related required guying, pole framing, system protection coordination will be re-assessed to conform to current installation standards.

2. Safety

Poor pole conditions, old porcelain insulators, undersized secondary bus, old cable terminations, and aging overhead transformers are a hazard for electrical flashover.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

n/a

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 46-A
Project Name: Replace Overhead Assets on John Street
System Type: *System Renewal*

C A T E G O R Y S P E C I F I C R E Q U I R E M E N T S

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

All overhead assets, structure, transformers, overhead wires, UG cable termination and related hardware, during patrol conducted in 2009, have been identified as in "poor" condition, and exceed their useful life.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The supply to this area impacts 330 customers that are mostly commercial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend of how and which assets fails. Momentary interruptions are expected due to flashovers without the entire asset to falling. Once a persistent failure reaches the breaking point, we expect approximately 90 minutes of outage time to allow for sectionalizing, approximately 29,700 customer minutes.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints, commercial businesses affected due to the outage require for power restorations

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Availability of resources will impact the project timing, and this is managed as part of the ongoing construction program.

Consequences for O&M System Costs Including Implications of Not Implementing:

There will be an increase of patrols due to momentary interruptions caused by flashovers in these assets causing an increase in O&M system costs.

Reliability and Safety Factors:

New installation will be more reliable, due to new, more technological advanced equipment, due to system upgrade to current installation standard. We expect to reduce or eliminate all possible existing safety hazards due resulting from existing aging equipment.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 46-A
Project Name: Replace Overhead Assets on John Street

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN
Engineering

GENERAL

Project Number: 46-B
Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm
Project Category: Rebuild Overhead Distribution System
System Type System Renewal
Customer Attachments/Load:
Project Manager: Daniela Motoc
Start Date: May 1, 2013
In Service Date: September 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$550,000	$358,919
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$550,000	$358,919
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$269,189	$89,730	$0

Risks to Completion and Risk Mitigation:
One major risk to job completion could be unforeseen issues when trying to break into the existing concrete encased duct structure to allow re-routing / replacement or splicing of the radial feed primary cables feeding five apartment buildings; Work must be completed before summer peak time considering the current express feeder configuration at Queen Mary to avoid putting the distribution system at risk when load transfer capacity is not available between Thomas MS and Kerr MS substations.

Comparative Information on Equivalent Historical Projects (if any):
Over the last three years we have successfully completed two similar projects that can be used as comparison: Cross Ave Rebuild, Trafalgar Rd Rebuild

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:
This budget represents the risk, value and cost to replace the overhead assets located on Queen Mary Dr, south of Riverside Dr, Bond St, and Chisholm St north of Lakeshore Rd W. This area was noted in poor condition during the overhead patrol reports and should be replaced in order to mitigate the risk of the assets failing along these stretches of road. Also any existing underground dip cables of insufficient length will be replaced or extended to the new pole. These roads have express feeders which are directly connected to the Municipal Substations.

Project #: 46-B
Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is a reduction in risk to the distribution system due to a limited capacity to perform load transfers between major Municipal Substations during summer loading periods.

Priority and Reasons for Priority: The proposed locations represents a high risk and high probability for equipment failure based on the asset age and condition. Failure can affect multiple Municipal Substation feeders or a Transformer Station feeder.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These assets are servicing some commercial, and both low and high density residential properties. We can expect to have multiple customers out of power in the event of a failure. Express feeders are installed on these roads, so an equipment failure would affect the whole feeder. If one of these assets fail, we would need to replace it immediately to new standards. If the aging assets are not replaced then the probability of failure increases, and in the event of a failure the affected customers would be out of power until crews can be dispatched to make repairs. The load on the feeder could be off up to 4 hours until the issue is resolved. Due to the age of all assets in this project we could expect failure of existing insulators, or spacer system, or switches or even pole failure with transformer on it that could cause oil spill and/or cause major safety hazards.

2. Safety
Poor pole conditions, old porcelain insulators, undersized secondary bus, old cable terminations, and aging overhead transformers are a hazard for electrical flashover.

3. Cyber-Security, Privacy
n/a

4. Co-ordination, Interoperability
Majority of the poles included in this project are owned by Bell ; multiple third party attachments are present at these locations; Planning/Design would have to be coordinated with owner of the poles and construction to be coordinated with the third party company having assets installed on these poles.

5. Economic Development
N/A

6. Environmental Benefits
N/A

Project #: 46-B
Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

All assets in this project have reached or exceeded their useful life; all assets during patrols have been identified in very poor condition backed up by health index of individual assets.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

1225 customers are affected, a mix of residential and commercial, some high density residential

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions will depend of how and which asset fails. Auto-recloses are expected to be seen due to flashovers whiteout entire asset to fail. Minimum 90 minutes outage is expected to allow sectionalizing; if failure of a specific assets for radial feed sections , such as cable terminations, cable failure, power restoration time will extend to min four hours ; 110,250 to 294,000 possible customer minutes

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local medium attention, due to longer outages required to restore power or "in construction site for a long period of time

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Possible restraints/ delays in acceptance from Pole Owners(Bell) in regard with proposed design, pole height increase, location; this is reason why planning/design need to be completed way in advanced to avoid delays in proposed construction schedule.

Consequences for O&M System Costs Including Implications of Not Implementing:

We can expect an increase of feeder patrols due to auto-recloses due to faults

Reliability and Safety Factors:

Newer assets are more reliable and minimize the risk to failure and/or flashover; switches replacement with gang operating new style switches will improve operations when sectionalized and improve safety

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 46-B
Project Name: Replace Overhead Assets on Queen Mary, Bond and Chisholm

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN
Engineering

GENERAL

Project Number: 46-C
Project Name: Replace Overhead Assets on Robinson St.
Project Category: Rebuild Overhead Distribution System
System Type System Renewal
Customer Attachments/Load:
Project Manager: Daniela Motoc

Start Date: September 15, 2013
In Service Date: June 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$720,000	$458,981
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$720,000	$458,981
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$344,236	$114,745

Risks to Completion and Risk Mitigation:
Delays may occur due to unforeseen conditions of existing old duct infrastructure for existing underground dip primary cables to be re-routed to the new poles. The existing cable might be too short to be transferred to the new poles or the existing vault structure might be found in poor condition and may require replacement.

Comparative Information on Equivalent Historical Projects (if any):
Over the last five years projects to replace similar equipment have been executed with costs between $50,000 to $400,000.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:
This budget represents the risk, value and cost to replace the overhead assets located on Robinson Street between Navy St and Allan St. Primary and secondary distribution system assets at this location were found in poor condition during the 2010 overhead patrol reports and should be replaced in order to mitigate the risk of the assets failing along this stretch of road. Also any existing underground dip cables of insufficient length should be replaced. These roads have express feeders which are directly connected to Municipal substations.

Project #: 46-C
Project Name: Replace Overhead Assets on Robinson St.

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main driver - Balancing asset management in conjunction with safety, reliability and cost. Reducing risk due to degrading service quality by installing new, more reliable assets, as well as following current installation standards and specifications.

Priority and Reasons for Priority: High risk, high probability. Failure can affect many customers due to current looped feed configuration and multiple express feeders interconnection. In case some of the assets fails prematurely, to restore power in this area funds will need to be available to replace assets regardless of set budgets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These assets are servicing commercial zoned properties and residential services. We could expect to have multiple customers off at a time. Some parts are directly connected to our express feeders, so problems would affect the whole feeder. If one of these assets fails, we would need to replace it immediately. If the aging assets are not replaced possible failures could cause faults and affect the entire feeder due to direct connections. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace. The load on the feeder could be off up to 4 hours until the issue is resolved. Due to the age of the assets we could expect a pole with a transformer to fall over which could cause the insulating oil to spill on a customers property. The current hydro poles are concrete pole, majority in very poor condition and due for replacement; if relocation of overhead conductor is required to eliminate a public safety hazard, then clearances are a significant issue. During design all pole loading, related required guying, pole framing, system protection coordination will be re-assessed to conform to current installation standards.

2. Safety

Poor pole conditions, old porcelain insulators, undersized secondary bus, old cable terminations, and aging overhead transformers are a hazard for electrical flashover.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

n/a

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 46-C
Project Name: Replace Overhead Assets on Robinson St.
System Type: *System Renewal*

C A T E G O R Y S P E C I F I C R E Q U I R E M E N T S

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

All overhead assets, structure, transformers, overhead wires, UG cable termination and related hardware, during patrol conducted in 2010, have been identified as in "poor" condition, and exceed their useful life.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The supply to this area impacts approximately 149 customers which are mostly commercial.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions will depend of how and which asset fails. Auto-recloses are expected to be seen due to flashovers whiteout entire asset to fail. Minimum 90 minutes outage is expected to allow sectionalizing; if failure of a specific assets for radial feed sections , such as cable terminations, cable failure, power restoration time will extend to min four hours ; 13,410 to 35,760 possible customer minutes

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints, commercial businesses affected due to the outage require for power restorations

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Availability of resources will impact the project timing, and this is managed as part of the ongoing construction program.

Consequences for O&M System Costs Including Implications of Not Implementing:

There will be an increase of patrols due to momentary interruptions caused by flashovers in these assets causing an increase in O&M system costs.

Reliability and Safety Factors:

New installation will be more reliable, due to new, more technological advanced equipment, due to system upgrade to current installation standard. We expect to reduce or eliminate all possible existing safety hazards due resulting from existing aging equipment.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 46-C

Project Name: Replace Overhead Assets on Robinson St.

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-A
Project Name:	Vault Transformer Replacements
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	September 1, 2013
In Service Date:	November 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$430,000	$316,241
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$430,000	$316,241
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$316,241	$0

Risks to Completion and Risk Mitigation:

One of the most significant risks to job completion involve the unknown condition of the existing infrastructure such as cables and duct systems. If addition repairs are required once the construction work starts, then the project will take much longer than planned. Alternate solutions such as cable injection will be considered to avoid project delays.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro Vault Transformer Replacement Program and similar projects have been built in the last few years. However we will continue to investigate new /improved/ more reliable technologies for use in vault applications.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost of the program to replace all live front vault transformers and NX Fuses from vault rooms. This is a proposed multi-year project to eliminate this type of transformer from our system due to access and operation issues. The average age of these assets is 38 years old. The NX style fuses without tabs cannot be safely operated at this time. Where possible, it is preferable to relocate the transformers outside of the buildings for ease of access using padmount transformers. Where this is not possible, submersible style transformers should be used within the vault rooms to make the installations dead front. This budget represents year two of the program. Location 2303 @ 492 Kerr St, Location 3272 @ 134 Randall St, and 2430 @ 444 Kerr St are proposed within this budget. All locations should be reviewed to determine if conversion to 27.6kV is possible. Project involved replacement of primary cables, transformers, fused switches and grounding system

Project #: 45-A
Project Name: Vault Transformer Replacements

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is a reduction in risk to the distribution system due to aging vault equipment. The vault transformers are the primary driver, but this replacement work will also include related vault switching equipment. Access restrictions to vault equipment result in repair times that are longer than similar equipment outside of a vault.

Priority and Reasons for Priority: High risk , high probability. Failure will affect many customers at the same time. The existing assets (primary cables, transformers, existing NX style fuses) that are proposed for replacement are reaching end of life and represent a reliability risk to our system. All locations in this project are radial feed supply, so failure of any of these assets will require emergency replacement.

Qualitative and Quantitative Analysis of Project and Project Alternatives: These types of assets typically supply large residential buildings or commercial units. We can expect to have multiple customers off at a time. If one of these assets fails, we would need to replace it immediately. If the aging assets are not replaced then a failures would cause the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be out of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The customer supply from the transformers could be off over 12 hours until a replacement solution could be engineered. Due to degrading conditions of the assets in these rooms we can expect to find transformers leaking insulating oil causing a spill within the vault rooms which may leak into the vault drains requiring MOE documentation.

2. Safety
Switching in the vault rooms for existing transformers using the old style air break switches present a high concerns for safety. The new equipment would comply with current safety standards.

3. Cyber-Security, Privacy
n/a

4. Co-ordination, Interoperability
n/a

5. Economic Development
n/a

6. Environmental Benefits
n/a

Project #: 45-A
Project Name: Vault Transformer Replacements
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Current assets (transformers, switches, connections, grounding system) are over 44 years old and noted in poor condition during patrols. Underground cables are past end of life and would be susceptible to failure if stressed.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Considering current grid configuration and cable connection, a cable failure will affect many customers connected on the circuit until sectionalizing, where possible is completed; 484 customers, mostly high density residential

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

The assets are aging which will make them more prone to failure. If the aging assets are not replaced possible failures could cause faults causing the upstream protection to open. Without existing fault indication or control to local feeders, customers would be out of power until a call came in and crews are dispatched to identify the issue and replace the fuses(s). The customer supply from transformers could be off over 12 hours until a replacement solution can be engineered.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Frequency of interruption will depend of which and how assets fail. We could expect momentary interruptions to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 90 minute to over 720 minute outage to allow for sectionalizing and/or asset replacement, 43,560 to 348,480 customer minutes. Medium risk.

5. Value of Customer Impact (high, medium, low)

medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of current NX style switches with equipment that meets current standards will result in more efficient operations.

Reliability and Safety Factors:

The project will be constructed to current standards and will use new, more reliable equipment; current transformers will be replaced to either padmounted dead front transformers of submersible style, built to current industry standards, which will allow for a system reliability increase as well as improvement for safety factors;

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-A
Project Name: Vault Transformer Replacements

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-D
Project Name:	Poletran Removals and Replace U/G Assets Various Locations
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 3, 2013
In Service Date:	June 30, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$370,000	$292,164
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$370,000	$292,164
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$78,963	$213,200	$0	$0

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro's asset renewal program, and similar poletran removals and underground rebuild projects have been executed consistently over many years. This is the last project in a multi-year program to remove poletran transformers.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for completion of the replacement of underground assets and poletran removals at 150 Water St, 3 Forsythe St, 130 Navy St, 1238 Crawford Court and 428 Donnybrook Rd The underground primary cables in this area are over 40 years old and represent some of the oldest underground cables in Oakville Hydro's distribution territory.

Project #: 45-D
Project Name: Poletran Removals and Replace U/G Assets Various Locations

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:
Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
The assets are significantly aged which make them prone to failure, requiring emergency replacement. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be out of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The outage resulting from equipment failure could last for up to four hours.

2. Safety
The poletrans (a combination steel pole that houses a transformer and supports a streetlight) pose safety concerns to field crews for operations and maintenance. As the existing poletrans continue to age, there is a chance of failure that represents a public safety risk.

3. Cyber-Security, Privacy
n/a

4. Co-ordination, Interoperability
n/a

5. Economic Development
n/a

6. Environmental Benefits
n/a

Project #: 45-D
Project Name: Poletran Removals and Replace U/G Assets Various Locations
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

The overhead assets were determined to be in a "poor" condition based on field inspection. The poletrans and underground cables represent some of the oldest underground assets in our system.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The proposed projects directly affects 4-10 residential customers, and represents a potential risk to 200-500 upstream customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the assets fail. We could expect to see auto-recloses due to flashovers without entire assets failing. Once the failure curve reaches the breaking point for a certain asset, we could expect an approximate 240 minute outage to allow for sectionalizing, approximately 2,400 customer minutes.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention

5. Value of Customer Impact (high, medium, low)

Medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of poletrans in these areas will decrease potential maintenance and repair costs. Possible cable failures will require contractors to dig splice pits, and crew hours to repair cables.

Reliability and Safety Factors:

The area will be rebuilt to new standards, which exceeded the standards of the original construction increasing safety and reliability (I.E. type of materials, installations standards, etc.)

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-D
Project Name: Poletran Removals and Replace U/G Assets Various Locations

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	45-Q
Project Name:	Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 1, 2013
In Service Date:	August 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$496,999	$385,205
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$496,999	$385,205
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$154,082	$231,123	$0

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro's asset renewal program, and similar overhead and underground rebuild projects have been executed consistently over many years.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for completion of the replacement of underground and overhead assets on Colchester, Oakhill, Dolphin and Albion. The underground primary cables in this area are approximately 38 years old and represent one of the oldest underground cables in Oakville Hydro's distribution territory. The overhead assets are of similar age, if not older. The primary cables are 38 years old in this area and are not in ducts.

Project #: 45-Q
Project Name: Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:
Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
The assets are significantly aged which make them prone to failure, requiring emergency replacement. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be out of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The outage resulting from equipment failure could last for up to four hours.

2. Safety
As the existing overhead equipment condition continues to degrade, there is a chance of failure that represents a public safety risk.

3. Cyber-Security, Privacy
n/a

4. Co-ordination, Interoperability
n/a

5. Economic Development
n/a

6. Environmental Benefits
n/a

Project #: 45-Q
Project Name: Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

The overhead assets were determined to be in a "poor" condition based on field inspection. The underground cables represent some of the oldest cables in our system.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The proposed project area directly affects 43 residential customers, and represents a potential risk to 507 upstream customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the assets fail. We could expect to see auto-recloses due to flashovers without entire assets failing. Once the failure curve reaches the breaking point for a certain asset, we could expect an approximate 240 minute outage to allow for sectionalizing, approximately 10,320 customer minutes.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to local Government, with possible local media attention

5. Value of Customer Impact (high, medium, low)

Medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 15 years. Possible cable failures will require contractors to dig splice pits, and crew hours to repair cables.

Reliability and Safety Factors:

The area will be rebuilt to new standards, which exceeded the standards of the original construction increasing safety and reliability (I.E. type of materials, spacing standards, etc.)

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-Q
Project Name: Replace U/G and O/H Assets Colchester,Oakhill, Dolphin, and Albion

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN
Engineering

GENERAL

Project Number:	45-X
Project Name:	Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln
Project Category:	Rebuild Underground Distribution System
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 1, 2013
In Service Date:	July 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$260,000	$184,665
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$260,000	$184,665
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$92,332	$92,332

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

This project is part of Oakville Hydro's asset renewal program, and similar overhead and underground rebuild projects have been executed consistently over many years.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the replacement of underground and overhead assets on Willowbrook Dr & Wendy Ln. The underground primary cables in this area are approximately 36 years old and represent one of the oldest underground cables in Oakville Hydro's distribution territory. The overhead assets are of similar age, if not older. The cables are 36 years old in this area and not in ducts.

Project #: 45-X
Project Name: Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:
Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives: The assets are aging which would make them more prone to failure requiring emergency replacement. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The load from the transformers could be off up to four hours until a new transformer could be installed or switching to isolate cable. Aging transformers could fail and allow insulating oil to escape onto sewer connections.

2. Safety
As the existing overhead equipment condition continues to degrade, there is a chance of failure that represents a public safety risk.

3. Cyber-Security, Privacy
N/A

4. Co-ordination, Interoperability
N/A

5. Economic Development
N/A

6. Environmental Benefits
N/A

Project #: 45-X
Project Name: Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Overhead wires, switches, and poles noted to be in poor to very poor condition. Underground wires are not installed in ducts, and are not TR-XLPE.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

The proposed project area directly affects 35 residential customers, and represents a potential risk to 233 upstream customers.

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see momentary interruptions due to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 90 to 240 minute outage to allow for sectionalizing, approximately 3,150 to 55,920 customer minutes. Medium Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to the company. Medium-Low risk.

5. Value of Customer Impact (high, medium, low)

Medium

Factors Affecting Project Timing, if any:

Oakville Hydro has incorporated proper planning for resources and materials in order to ensure project completion on time.

Consequences for O&M System Costs Including Implications of Not Implementing:

Replacement of wood poles in this area will decrease the required testing and treatment costs for the next 15 years. Possible cable failures will require contractors to dig splice pits, and crew hours to repair cables.

Reliability and Safety Factors:

The area will be rebuilt to new standards, which exceeded the standards of the original construction increasing safety and reliability (I.E. type of materials, spacing standards, etc.)

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

From a system configuration perspective the project is like for like, however new equipment will be used which is expected to increase reliability in this area.

Project #: 45-X
Project Name: Replace U/G and O/H Assets on Willowbrook Dr and Wendy Ln

OTHER INFORMATION

2014 CAPITAL PLAN
Engineering

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

GENERAL

Project Number:	42-B
Project Name:	Live front Padmount Transformer Replacements
Project Category:	Transformer Replacements and Voltage Conversion
System Type	System Renewal
Customer Attachments/Load:	
Project Manager:	Daniela Motoc
Start Date:	June 1, 2013
In Service Date:	May 30 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$350,000	$275,730
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$350,000	$275,730
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$82,719	$193,011	$0	$0

Risks to Completion and Risk Mitigation:

This project involves replacement of system equipment in close proximity to commercial customer property. The risk of public resistance to change is mitigated by communicating project plans with customers impacted to set appropriate expectations.

Comparative Information on Equivalent Historical Projects (if any):

Similar three phase transformer installations have been completed for all industrial/commercial services which can provide comparative information regarding costs and requirements.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for completion of the program to replace all of the remaining Live front Padmount Transformers in Oakville Hydro's distribution territory. Oakville Hydro has phased these transformers out over time and only a handful remain in the field with no straight replacement stock available. On average these units are 40 years old. This budget represents year one of the program. Location 4371 at 215 Rebecca St is proposed for replacement, and is a candidate for voltage conversion from 4kV to 27.6kV. Location 4267 and 4588 at 1005 and 1027 Speers Rd are proposed for replacement. These three transformers are candidates for voltage conversion from 4kV to 27.6kV, and should be placed on a loop feed. This budget should cover the cost of all cable replacements and pole upgrades required to perform the work.

Project #: 42-B
Project Name: Live front Padmount Transformer Replacements

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system.

Priority and Reasons for Priority:
Within these assets classes the proposed replacement area is composed of distribution assets that have been inspected and have the lowest condition rating.

Qualitative and Quantitative Analysis of Project and Project Alternatives: The assets are older which would make them more prone to failure requiring replacement without a capital budget. Typically installed to old standards and without proper transformer vaults, it would require replacement onto a new pad. If the aging assets are not replaced possible failures could cause faults causing the lateral fuses to open. With no existing fault indication or control to local feeders, customers would be off of power until a call came in and crews could be dispatched to identify the issue and replace the fuse(s). The load from the transformers could be off over 12 hours until a replacement solution could be engineered. Aging transformers could rust enough to allow insulating oil to escape onto private property.

2. Safety

Due to the transformer having live contacts it is possible for an employee to fall into the energized primary while doing inspections every three years. New transformer standards require a dead-front style to be used, which limits the danger to crews.

3. Cyber-Security, Privacy

N/A

4. Co-ordination, Interoperability

N/A

5. Economic Development

N/A

6. Environmental Benefits

N/A

Project #: 42-B
Project Name: Live front Padmount Transformer Replacements
System Type: *System Renewal*

CATEGORY SPECIFIC REQUIREMENTS

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure:

1. Condition of Asset vs. Typical Life Cycle and Performance Record

Condition listed between "Fair" and "Poor" per Health Index. Typical life cycle 35 years.

2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure

Four to Ten commercial customers serviced from these locations

3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)

Frequency of interruptions would depend on how the asset fails. We could expect to see auto-recloses due to flashovers without the entire asset failing. Once the failure curve reaches the breaking point we could expect an approximate 720 minute outage to allow for sectionalizing, approximately 2880 to 7200 customer minutes. High Risk.

4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)

Expect customer complaints to regulator, with possible regional media attention. Medium-High Risk.

5. Value of Customer Impact (high, medium, low)

High

Factors Affecting Project Timing, if any:

Three of these assets are proposed to be replaced per year over the forecast period. Currently 41 of these assets in the system, at an investment of three per year every unit is proposed to be replaced after TUL has passed. High priority vs. other projects.

Consequences for O&M System Costs Including Implications of Not Implementing:

Expected increase of patrols due to auto-recloses caused by flashovers in these assets causing an increase in O&M system costs.

Reliability and Safety Factors:

Newer padmount transformers are deadfront construction, where the primary cables are insulated from the crews working on the equipment. Newer installations have vaults underneath the transformers to allow for extra cable to be stored in the case failure occurs and extra slack is required without replacing the entire cable.

Analysis of Project Benefits and Costs with Alternative Comparison (if the project is "like for like" renewal and has been configured at extra cost, provide an analysis of project benefits):

N/A

Project #: 42-B
Project Name: Live front Padmount Transformer Replacements

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN
Engineering

G E N E R A L

Project Number:	44H
Project Name:	27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403
Project Category:	27.6kV Additions
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	
In Service Date:	June 20, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$500,000	$420,973
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$500,000	$420,973
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$420,973	$0	$0

Risks to Completion and Risk Mitigation:

There is minimal risk to completion, this project is to support load growth in the area.

Comparative Information on Equivalent Historical Projects (if any):

Oakville Hydro has completed many similar projects in the past to extend or construct new circuits for system access activities.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:

This budget represents the risk, value and cost for completion of work required to add an additional 27.6kV feeder on Upper Middle Road E, from Ninth Line to Highway #403, to support load growth in the Winston Business Park. This will also support future load growth in the next phase of new development in the area (Winston Park West). This project includes one additional fully rated 27.6kV circuit to interconnect with the existing network.

Project #: 44H
Project Name: 27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver: Support load growth and increased supply reliability to Winston Business Park. Support load growth for next phase of development, Winston Park West.

Priority and Reasons for Priority: Regulatory requirement and non-discretionary project, driven by development.

Qualitative and Quantitative Analysis of Project and Project Alternatives: The addition of this circuit will support load growth in the area, improve reliability and provide supply for new developments. The design and construction will be done in accordance with the most recent design and safety standards, and in the most cost effective manner.

2. Safety
n/a

3. Cyber-Security, Privacy
n/a

4. Co-ordination, Interoperability
n/a

5. Economic Development
This project supports economic development by providing supply facilities for new development and jobs.

6. Environmental Benefits
n/a

Project #: 44H
Project Name: 27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:

Customer drives the timing of the service requirement and Oakville Hydro prioritizes projects within its project planning schedule by meeting their in-service dates.

Factors Relating to Customer Preferences or Input:

n/a - the scope of this project is within the municipal road allowance and does not have direct impact on private property.

Factors Affecting the Final Cost of the Project:

Final cost is based upon actual cost of the construction, factors that can affect actual costs include: unexpected changes to scope, number of customer requests (anticipated vs. actual), customer initiated changes, weather and/or field conditions.

How Controllable Costs have been Minimized:

Prudent cost estimates are based on standardized materials, unit rate construction contracts, and appropriate equipment sizing.

Identify if Other Planning Objectives are Met by the Project, if so which ones:

The addition of this circuit will not only supply load growth and new developments but improve the supply reliability in the area.

Options Considered and Summary of Analysis:

n/a

Results of Final Economic Valuation, if applicable:

n/a

System Impacts (Nature, Magnitude and Costs):

n/a

Project #: 44H
Project Name: 27.6kV Circuit, Upper Middle Rd, Ninth Line to Highway #403

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number: 14-50C
Project Name: New Development Investment
Project Category: New Development / Services
System Type System Access
Customer Attachments/Load:
Project Manager: Daniela Motoc

Start Date:
In Service Date: December 31, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$2,691,000	$2,280,508
Contributed Capital:	$2,191,000	$1,856,780
OHEDI Capital Cost:	$500,000	$423,729
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$105,932	$169,492	$148,305

Risks to Completion and Risk Mitigation:
n/a

Comparative Information on Equivalent Historical Projects (if any):
Oakville Hydro continues to have new customer connections on an annual basis. The value and number of connections vary year to year based on market and new construction demands. These projects are commonly included in Oakville Hydro's project plans.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:
New residential subdivisions require an economic evaluation to determine Oakville Hydro's capital contribution requirements.

E V A L U A T I O N C R I T E R I A A N D I N F O R M A T I O N

Project #: 14-50C
Project Name: New Development Investment

1. Efficiency, Customer Value, Reliability

Main Driver:
This is a regulatory requirement based on the prescribed economic evaluation methodology.

Priority and Reasons for Priority:
n/a

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Represents capital contributed for investment in new developments.

2. Safety

n/a

3. Cyber-Security, Privacy

n/a

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 14-50C
Project Name: New Development Investment
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
Oakville Hydro assesses the connection of new customers on an annual basis.

Factors Relating to Customer Preferences or Input:
n/a

Factors Affecting the Final Cost of the Project:
The number of customer connections vary from year to year.

How Controllable Costs have been Minimized:
n/a

Identify if Other Planning Objectives are Met by the Project, if so which ones:
n/a

Options Considered and Summary of Analysis:
n/a

Results of Final Economic Valuation, if applicable:
Final economic evaluations are done on a site by site basis.

System Impacts (Nature, Magnitude and Costs):
n/a

Project #: 14-50C
Project Name: New Development Investment

O T H E R I N F O R M A T I O N

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN
Engineering

GENERAL

Project Number:	14-54
Project Name:	New General Services
Project Category:	New Development / Services
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Jon Foreshew
Start Date:	January 1, 2014
In Service Date:	December 31, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$787,000	$598,945
Contributed Capital:	$325,000	$247,341
OHEDI Capital Cost:	$462,000	$351,604
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$87,901	$87,901	$87,901	$87,901

Risks to Completion and Risk Mitigation:

General service and large industrial customer requirements drive project timing. Oakville Hydro maintains a close relationship with these customers to ensure that service dates are met.

Comparative Information on Equivalent Historical Projects (if any):

General service requirements are an annual requirement based on the needs and demands of our customers. Services vary depending on size and complexity.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:
This budget represents the risk, value and cost for any new general services in Oakville's distribution territory. Per Oakville Hydro conditions of service, Oakville Hydro funds transformation up to 2500kVA.
The Electricity Act states:
A distributor shall connect a building to its distribution system if, a) the building lies along any of the lines of the distributor's distribution system; and b) the owner, occupant or other person in charge of the building requests the connection in writing.

Project #: 14-54
Project Name: New General Services

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The general service customer requires service for their proposed facilities.

Priority and Reasons for Priority:
Regulatory requirement and non-discretionary project, initiated by customers.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Ensure compliance with Section 28 of the Electricity Act and customer satisfaction. The costs associated with this project are partially funded by the customer based upon calculated estimates.

2. Safety
New services are designed and constructed to ESA regulations.

3. Cyber-Security, Privacy
N/A

4. Co-ordination, Interoperability
N/A

5. Economic Development
Installation of distribution equipment allows for local economic development and jobs.

6. Environmental Benefits
N/A

Project #: 14-54
Project Name: New General Services
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:

Customer drives the timing of the service requirement and Oakville Hydro prioritizes projects within its project planning schedule by meeting their in-service dates.

Factors Relating to Customer Preferences or Input:

Oakville Hydro works with potential customers to ensure that their needs are met. Projects are designed according to their input, within the guidelines of the conditions of service.

Factors Affecting the Final Cost of the Project:

Final cost is based upon actual cost of the construction, factors that can affect actual costs include: unexpected changes to scope, number of customer requests (anticipated vs. actual), customer initiated changes, weather and/or field conditions.

How Controllable Costs have been Minimized:

Prudent cost estimates are based on standardized materials, unit rate construction contracts, and appropriate equipment sizing. For these project, the customer contributes to all costs except for the transformer.

Identify if Other Planning Objectives are Met by the Project, if so which ones:

n/a

Options Considered and Summary of Analysis:

These projects are initiated by the customer, and Oakville Hydro can provide the customer with some options to align with the needs of the customer provided that the project satisfies all technical and safety requirements.

Results of Final Economic Valuation, if applicable:

n/a

System Impacts (Nature, Magnitude and Costs):

Any new services that would impact our system from a loading perspective are captured under a specific project. The services included in this project do not generally impact the existing system.

Project #: 14-54
Project Name: New General Services

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

G E N E R A L

Project Number:	14-61
Project Name:	Distribution Meters
Project Category:	Distribution Meters / Wholesale Meter Upgrades
System Type	System Access
Customer Attachments/Load:	
Project Manager:	Bob Myers
Start Date:	January 1, 2014
In Service Date:	December 31, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$605,625	$481,706
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$605,625	$481,706
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$101,850	$128,700	$102,600	$272,475

Risks to Completion and Risk Mitigation:

Comparative Information on Equivalent Historical Projects (if any):

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

Project Summary:

This budget is for the required distribution meters in Oakville's distribution territory. The Distribution System Code states: 5.1.1 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. This project includes new residential meters equipped with zigbee to facilitate "real-time" data access and "behind the meter" services, new multi-residential meters, new commercial meters, commercial meter communication conversion from dial up to flex net, and a new Tower Gateway Base ("TGB") station to support smart meter data collection.

EVALUATION CRITERIA AND INFORMATION

Project #: 14-61
Project Name: Distribution Meters

1. Efficiency, Customer Value, Reliability

Main Driver:
This project supplies metering infrastructure to measure consumption as required for new services. A new TGB is required to address new residential and small commercial growth in Oakville. Each TGB will reach its saturation point for number of meters it can read and a new TGB must be installed to communicate with new smart meters. New development currently under-way north of Hwy 5 in Oakville will result in the requirement for a 6th TGB since existing TGB's are at capacity and will not be capable of communicating with the new meters.

Priority and Reasons for Priority:
Meter replacement is a mandatory requirement as per the Distribution System Code. The TGB is required to meet requirements as a result of new growth.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Ensure compliance with Section 5 of the Distribution Code

2. Safety

n/a

3. Cyber-Security, Privacy

Oakville Hydro operates an encrypted smart meter communication network.

4. Co-ordination, Interoperability

n/a

5. Economic Development

n/a

6. Environmental Benefits

n/a

Project #: 14-61
Project Name: Distribution Meters
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
New development activity and new customers drive the timing for this project.

Factors Relating to Customer Preferences or Input:
Zigbee meter communications facilitate future "real-time" data access and "behind the meter" services.

Factors Affecting the Final Cost of the Project:
New development activity and new customers drive the cost for this project.

How Controllable Costs have been Minimized:
Crew site visits are optimized by managing expectations and collaborating with site contractors.

Identify if Other Planning Objectives are Met by the Project, if so which ones:
Commercial meters will be upgraded from simple dial-up to smart meters connected to the existing flex net communication network.

Options Considered and Summary of Analysis:
Older meter technologies will continue to generate connectivity issues if they continue to be used.

Results of Final Economic Valuation, if applicable:

n/a

System Impacts (Nature, Magnitude and Costs):

n/a

Project #: 14-61
Project Name: Distribution Meters

OTHER INFORMATION

2014 CAPITAL PLAN
Engineering

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

GENERAL

Project Number: 15-E
Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd
Project Category: Road Widening (Dependent on Road Work - No Hydro Control)
System Type System Access
Customer Attachments/Load:
Project Manager: Jon Foreshew

Start Date: February 1, 2014
In Service Date: September 5, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$358,135	$244,991
Contributed Capital:	$134,000	$91,191
OHEDI Capital Cost:	$224,135	$153,800
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$76,900	$76,900	$0

Risks to Completion and Risk Mitigation:
Before design work can begin, Oakville Hydro requires final road design from the Town of Oakville. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the Town of Oakville will impact the timing for construction. Regular communication and ongoing meetings are maintained with the Town of Oakville to provide clear line of sight on project timing.

Comparative Information on Equivalent Historical Projects (if any):
Road widening projects are completed annually with the Town of Oakville, Region of Halton, and Ministry of Transportation. The value and timing of past projects have varied depending on the road authorities' construction program.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:
n/a

Project Summary:
The North Service Rd will be widened from the existing 2 lanes into 4 lanes from 8th Line to Iroquois Shore Rd. This represents 1 km of roadway and at least 20 new poles. This project will require relocation of poles and associated distribution equipment to make room for the new lanes. As this equipment is relocated there will be associated planned customer outages.

Project #: 15-E
Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is a third party road design change as a result of an infrastructural need identified by the Town of Oakville.

Priority and Reasons for Priority:
This is a regulatory requirement to comply with distribution plan relocation when requested by road authorities.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Subject to section 5 of the Government of Ontario's Public Service Works on Highway Act, R.S.O. 1990, Chapter P.49, Oakville Hydro is required to take up, remove or change the location of appliances or works, or make due compensation to the road authority for such loss or expense. Under the OEB enforcement the Board may impose an administrative penalty of $20,000 per day for each day or part day on which the contravention occurred or continues.

2. Safety
New distribution equipment will be designed and constructed according to new safety standards.

3. Cyber-Security, Privacy
n/a

4. Co-ordination, Interoperability
n/a

5. Economic Development
n/a

6. Environmental Benefits
n/a

Project #: 15-E
Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
Before design work can begin, Oakville Hydro requires final road design from the Town of Oakville. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the Town of Oakville will impact the timing for construction.

Factors Relating to Customer Preferences or Input:
Customers that will be impacted by a scheduled outage will be contacted in advance.
The placement of new poles will be reviewed with the Town of Oakville for their approval.

Factors Affecting the Final Cost of the Project:
Design changes from the Town of Oakville, field conditions, scheduling delays, and restricted working hours will impact the final cost of the project.

How Controllable Costs have been Minimized:
Material costs will be controlled using standardized design and material selection. Crews deployment will be optimized based on allowable working hours. Typically half of the labour and vehicle costs are recovered from the Town of Oakville.

Identify if Other Planning Objectives are Met by the Project, if so which ones:
Asset replacement objectives are also being met in this project. The new distribution equipment is installed in place of the existing ageing equipment.

Options Considered and Summary of Analysis:
The designated project area is set by the Town of Oakville, however, the specific placement of Oakville Hydro's distribution equipment and system functionality is assessed and optimized.

Results of Final Economic Valuation, if applicable:
n/a

System Impacts (Nature, Magnitude and Costs):
n/a

Project #: 15-E
Project Name: North Service Rd Widening, 8th Line to Iroquois Shore Rd

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

G E N E R A L

Project Number: 15-I
Project Name: Road Widening TBD
Project Category: Road Widening (Dependent on Road Work - No Hydro Control)
System Type System Access
Customer Attachments/Load:
Project Manager: Jon Foreshew

Start Date:
In Service Date: March 19, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$474,000	$309,752
Contributed Capital:	$163,000	$106,518
OHEDI Capital Cost:	$311,000	$203,234
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$0	$101,617	$101,617

Risks to Completion and Risk Mitigation:
Before design work can begin, Oakville Hydro requires final road design from the road authority. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the road authority will impact the timing for construction. Regular communication and ongoing meetings are maintained with the road authority to provide clear line of sight on project timing.

Comparative Information on Equivalent Historical Projects (if any):
Road widening projects are completed annually with the Town of Oakville, Region of Halton, and Ministry of Transportation. The value and timing of past projects have varied depending on the road authorities' construction program.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

n/a

Project Summary:
Historically, Oakville Hydro has been engaged in annual road widening requirements, and this project represents road widening work that has not been specifically identified by the road authorities.

EVALUATION CRITERIA AND INFORMATION

Project #: 15-I
Project Name: Road Widening TBD

1. Efficiency, Customer Value, Reliability

Main Driver:
The main driver for this project is a third party road design change as a result of an infrastructural need identified by the road authority.

Priority and Reasons for Priority:
This is a regulatory requirement to comply with distribution plan relocation when requested by road authorities.

Qualitative and Quantitative Analysis of Project and Project Alternatives:
Subject to section 5 of the Government of Ontario's Public Service Works on Highway Act, R.S.O. 1990, Chapter P.49, Oakville Hydro is required to take up, remove or change the location of appliances or works, or make due compensation to the road authority for such loss or expense. Under the OEB enforcement the Board may impose an administrative penalty of $20,000 per day for each day or part day on which the contravention occurred or continues.

2. Safety
New distribution equipment will be designed and constructed according to new safety standards.

3. Cyber-Security, Privacy
n/a

4. Co-ordination, Interoperability
n/a

5. Economic Development
n/a

6. Environmental Benefits
n/a

Project #: 15-I
Project Name: Road Widening TBD
System Type: *System Access*

CATEGORY SPECIFIC REQUIREMENTS

Factors Affecting Timing/Priority:
Before design work can begin, Oakville Hydro requires final road design from the road authority. If these road design plans are delayed, then this project will be delayed. Also, upon completion of the road design, any land acquisition delays from the road authority will impact the timing for construction.

Factors Relating to Customer Preferences or Input:
Customers that will be impacted by a scheduled outage will be contacted in advance.
The placement of new poles will be reviewed with the road authority for their approval.

Factors Affecting the Final Cost of the Project:
Design changes from the road authority, field conditions, scheduling delays, and restricted working hours will impact the final cost of the project.

How Controllable Costs have been Minimized:
Material costs will be controlled using standardized design and material selection. Crews deployment will be optimized based on allowable working hours. Typically half of the labour and vehicle costs are recovered from the road authority.

Identify if Other Planning Objectives are Met by the Project, if so which ones:
Asset replacement objectives are also being met in this project. The new distribution equipment is installed in place of the existing ageing equipment.

Options Considered and Summary of Analysis:
The designated project area is set by the road authority, however, the specific placement of Oakville Hydro's distribution equipment and system functionality is assessed and optimized.

Results of Final Economic Valuation, if applicable:
n/a

System Impacts (Nature, Magnitude and Costs):
n/a

Project #: 15-I
Project Name: Road Widening TBD

OTHER INFORMATION

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Engineering

GENERAL

Project Number:	14-62
Project Name:	2014 Fleet
Project Category:	Vehicles
System Type	General Plant
Customer Attachments/Load:	
Project Manager:	Chris Cudmore
Start Date:	January 1, 2014
In Service Date:	November 1, 2014

	Old CGAAP	New CGAAP
Total Capital Cost:	$404,000	$384,762
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$404,000	$384,762
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:				

Risks to Completion and Risk Mitigation:

Changes to type of vehicle e.g. HYBRID vs. regular

Comparative Information on Equivalent Historical Projects (if any):

Annual projects for fleet replacement, projects vary depending on fleet age and vehicle type.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

This budget represents the risk, value and cost for replacing existing fleet to be purchased in 2014. This budget represents the risk, value and cost for vehicles to be purchased in 2014. Four existing pickup trucks are proposed to be replaced with new 2014 hybrid pickup type vehicles having an active fuel management system, the following trucks are proposed for replacement #69, 75, 80, and 65 ranging between 8-11 years old. One existing car #68, which is ten years old, is proposed to be replaced with a new 2014 hybrid car type vehicle having an active fuel management system. One existing van #77, which is nine years old, is proposed to be replaced with new 2014 hybrid van type vehicles having an active fuel management system. One existing blocker truck chassis #20, which is 24 years old, is proposed to be replaced with a large used truck chassis. One existing warehouse forklift #406, which is 23 years old, is proposed for replacement.

Project #: 14-62
Project Name: 2014 Fleet

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:
Replacement of aging fleet assets.

Priority and Reasons for Priority:
Fleet asset replacement program. Replacements due to age and reliability of fleet assets.

Qualitative and Quantitative Analysis of Project and Project Alternatives: Hybrid vehicles will result in reduced fuel consumption. The proposed fleet vehicles for replacement have reached the end of useful life. Reduced operating and maintenance expenses are expected.

2. Safety
The replaced vehicles will be matched to the work requirements and will reduce the risk of improper work methods. The timing for fleet replacement ensures that vehicles are replaced before they deteriorate to a degree that represents an operational safety hazard.

3. Cyber-Security, Privacy
N/A

4. Co-ordination, Interoperability
N/A

5. Economic Development
Proposed fleet asset replacements will be tendered to local dealerships.

6. Environmental Benefits
New fleet vehicles have better fuel efficiency and lower emissions.

Project #: 14-62
Project Name: 2014 Fleet
System Type: *General Plant*

CATEGORY SPECIFIC REQUIREMENTS

Impact of Deferral/"Do Nothing" Option

Potential for increased maintenance and fuel costs; reduced reliability.

Net Benefits of Project in Monetary Terms (where practicable)

Reduced maintenance and fuel costs.

Project #: 14-62
Project Name: 2014 Fleet

O T H E R I N F O R M A T I O N

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

IT

G E N E R A L

Project Number:	14-64D
Project Name:	Business Systems Applications
Project Category:	Administration - IT
System Type	General Plant
Customer Attachments/Load:	
Project Manager:	Business Systems Analyst
Start Date:	
In Service Date:	

	Old CGAAP	New CGAAP
Total Capital Cost:	$203,000	$203,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$203,000	$203,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$0	$203,000	$0	$0

Risks to Completion and Risk Mitigation:

Microsoft Dynamics GP 2013 statement of direction is clear and was implemented Q4 - 2012. We will upgrade our system in 2014 once all investigating has been complete in 2013. There are no risks to completion.

Comparative Information on Equivalent Historical Projects (if any):

Microsoft Dynamics GP has been maintained since the initial cutover from JD Edwards in 2008. Average annual costs for new additions to the software have been necessary to increase functionality as the business requirements change. This upgrade will provide the functionality to help reduce the need for new additional software. The GP strategy is to use the current investment as much as possible and purchase new software only where necessary.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

N/A

Project Summary:

Initiatives include:

Harris Collection Project - $25K to automate our current collection methodology and create an efficient and effective process

Northstar modifications - implementation of Automation Platform including custom Cognos and SQL rule development to enhance Oakville Hydro billing processes due to introduction of added complexities in billing.

Workforce Management (WFM) improvements - Oakville Hydro will be automating the service orders currently used with the Halton Region along with improving Oakville Hydro's existing WFM used for electric service orders. This includes implementation of electronic service orders for the Region, testing of service orders and its affect on billing processes, and introducing WFM to new Oakville Hydro business processes

GP ERP system Upgrade - This is a substantial upgrade from GP 2010 to GP 2013. Activities around the upgrade features will require a full re-implementation and integration of existing software to the new GP2013 system. This upgrade required to allow us to take advantage of new features that not only assist in daily activities but also for analysis and reconciliations. There should be no additional software required for the ERP system in 2014 while we are implementing the new version.

Business Intelligence - Good business intelligence tools will need further development to provide good analysis to the business.

Project #: 14-64D
Project Name: Business Systems Applications

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

It is important for software to be maintained at the Vendors current versions to take advantage of new features in functionality and security. Oakville Hydro does not want to leave the upgrade for too long as GP and all related software are developing at the same rate and we are not able to take advantage of any of the new features from any of the existing related software. Deferral will result in a complete re-install rather than an upgrade if the existing system becomes too dated.

Priority and Reasons for Priority:

GP - High - This is the core ERP/finance/Job related software. Support on the existing GP 2010 will end Oct 2015. To have this system completed by 2014 will ensure there is no risks of increased costs from vendors to support the system after Microsoft has completed it's support. GP2013 has features that may assist in the development of asset management strategies. GP2013 is required to be in place and operating in order to develop these strategies.

Harris Collection Project - High - automation of collection process to increase efficiency, timeliness and reduce bad debt - We are currently receiving complaints from some customers in regards to the current process. We would like to make a change to implement an enhanced version of credit scoring so that letters, notices and disconnections are not directed to customers with good payment history.

Northstar Modification - the introduction of efficiencies in the Meter to Cash process through automation of service orders and CIS processes will help reduce Oakville Hydro's dependence on manual processes. This will help reduce billing errors, delayed bills, and improve utilization of resources, which will serve to benefit Oakville customers.

Qualitative and Quantitative Analysis of Project and Project Alternatives:

Harris Collection Project - goal of project is to reduce bad debts and to minimize customer complaints.

2. Safety

N/A

3. Cyber-Security, Privacy

Microsoft Dynamics GP 2013 is an internal system that resides in the existing infrastructure

4. Co-ordination, Interoperability

The CIS based Automation Platform will enable the development of automated meter to cash business processes.

5. Economic Development

6. Environmental Benefits

N/A

Project #: 14-64D
Project Name: Business Systems Applications
System Type: *General Plant*

C A T E G O R Y S P E C I F I C R E Q U I R E M E N T S

Impact of Deferral/"Do Nothing" Option

GP - The business is requesting access to new features that are available in the GP2013 environment. If the upgrade is not completed, new software will need to be sourced to cover the deficiencies of the existing GP 2010 version.

Harris Collection Project - service would continue as status quo with the possible increase of bad debts due to the manual process. Reduction of complaints would not be minimized.

Northstar Modification and Workforce Management Improvements - without improving the automation within Oakville's CIS and WFM, the meter to cash processes will continue to be manual process where human errors are more prevalent, resulting in billing errors. Due to the requirement to operate in 'real time' since the introduction of smart meters, automation is critical in the meter to cash process.

Net Benefits of Project in Monetary Terms (where practicable)

Mandatory upgrade for applications

Project #: 14-64D
Project Name: Business Systems Applications

OTHER INFORMATION

Microsoft Dynamics GP 2013 is scheduled to be released in Calendar Q4 of 2012. The release marks another milestone for the Microsoft Dynamics GP product by:
-Delivering a Web Client option
-deployment options and capabilities
-Enhancing the core functionality
-Making Rapid Start Services for Microsoft Dynamics GP available

2014 CAPITAL PLAN

IT

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

GENERAL

Project Number: 14-64F
Project Name: IT Infrastructure
Project Category: Administration - IT
System Type General Plant
Customer Attachments/Load:
Project Manager: Infrastructure Specialist

Start Date: January 2, 2014
In Service Date: Various dates throughout the year

	Old CGAAP	New CGAAP
Total Capital Cost:	$420,000	$420,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$420,000	$420,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:	$105,000	$105,000	$105,000	$105,000

Risks to Completion and Risk Mitigation:
N/A

Comparative Information on Equivalent Historical Projects (if any):
The ongoing maintenance of our infrastructure is core to maintaining the systems the business requires. Asset plans in the IT Strategy define a good basis for a plan that makes sense from a system and cost point of view. In 2011 and 2012 there was increased focus on operational IT projects rather than IT infrastructure projects. 2014 continues the 2013 infrastructure improvements with a focus on critical systems to support the distribution system (e.g. SCADA) and general operations. Key areas include security and business continuity.

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:
N/A

Project Summary:
This is a combined project taking into account all infrastructure changes to support the organization in the initiatives.

Project #: 14-64F
Project Name: IT Infrastructure

1. Efficiency, Customer Value, Reliability

Main Driver:

Infrastructure Stability to support the organization

Priority and Reasons for Priority:

Medium - Regular replacement of existing system for system security and business continuity

Qualitative and Quantitative Analysis of Project and Project Alternatives:

This project is new technologies, sustaining replacements and increased capacity to keep up with the demands of the business.

2. Safety

N/A

3. Cyber-Security, Privacy

IT currently supports three infrastructures.
-Operations (SCADA, OMS, GIS)
-Corporate (ERP,
-AMI/CIS (Metering, Customer services, Billing)
All changes to the infrastructure follow change management process that takes into account the Cyber Security, Privacy

4. Co-ordination, Interoperability

This project is new technologies, sustaining replacements and increased capacity to keep up with the demands of the business.
The implementation of all IT resources follows NERC , CIP001-CIP009 compliance and ISO27000 standards

5. Economic Development

6. Environmental Benefits

Newer technologies provide a greener footprint.

Project #: 14-64F
Project Name: IT Infrastructure
System Type: *General Plant*

C A T E G O R Y S P E C I F I C R E Q U I R E M E N T S

Impact of Deferral/"Do Nothing" Option

Out of date equipment and demand for higher resources will result in deficiencies in the organization's other projects and ongoing operating activities.

Net Benefits of Project in Monetary Terms (where practicable)

Project #: 14-64F
Project Name: IT Infrastructure

O T H E R I N F O R M A T I O N

The 2014 Infrastructure project includes some of the following as a means to secure the right resources to support the initiatives of the organization.
-Further virtualization for the server farm, and new licenses for servers/virtualization from Microsoft as part of our ongoing project to consolidate and maintain the IT infrastructure. Licenses are purchased through the current EA agreement with Microsoft.
-Further desktop replacements for 5 year asset management plan
-Further storage needs for increase in storage from last year
-Switches, routers, network connections that were previously installed will need replacement and redundancy
-Foundry switches were installed in 2010 at all substations. These switches will require investigation and redundancy in 2014
-Increased Mobile Security for all mobile devices. -IPSec VPN Tunnel using 4G Mobile cellular VPN connectivity.
-Central administration tool to manage (diagnose, support) all mobile devices include E-Mobile devices

OAKVILLE HYDRO ELECTRICITY DISTRIBUTION

2014 CAPITAL PLAN

Buildings

GENERAL

Project Number:	
Project Name:	HVAC upgrade - 5 year replacement program
Project Category:	Administration - Buildings
System Type	General Plant
Customer Attachments/Load:	
Project Manager:	Ron Vandermolen
Start Date:	
In Service Date:	ongoing

	Old CGAAP	New CGAAP
Total Capital Cost:	$230,000	$230,000
Contributed Capital:	$0	$0
OHEDI Capital Cost:	$230,000	$230,000
OM&A Costs:		

	Q1	Q2	Q3	Q4
Expenditure Timing:		$115,000	$115,000	$0

Risks to Completion and Risk Mitigation:

Comparative Information on Equivalent Historical Projects (if any):

Total Capital and OM&A Costs for Renewable Energy Generation portion of project:

Project Summary:

Replacement of HVAC and mechanical equipment (approx. 85 units) over a five year period. Three units have been replaced since 2011, and several units have had compressor replacements and/or major repairs to date.

Project #: n/a
Project Name: HVAC upgrade - 5 year replacement program

EVALUATION CRITERIA AND INFORMATION

1. Efficiency, Customer Value, Reliability

Main Driver:

Priority and Reasons for Priority:

Qualitative and Quantitative Analysis of Project and Project Alternatives: This is a proactive plan to replace units that have reached end of life cycle, as they are original equipment (1994). We are experiencing more frequent breakdowns of units requiring replacement, particularly with units that are rooftop and exposed to the elements. Lead time for replacement units on an emergency basis varies from 4-10 weeks depending on make and model type/size. Repair costs on these aging units continue to increase. Newer technology will result in more energy efficient products, improved operations, improved reliability and decreased maintenance costs - as well as ensure smooth operation of the facility.

2. Safety

3. Cyber-Security, Privacy

4. Co-ordination, Interoperability

5. Economic Development

6. Environmental Benefits

Project #: n/a
Project Name: HVAC upgrade - 5 year replacement program
System Type: *General Plant*

C A T E G O R Y   S P E C I F I C   R E Q U I R E M E N T S

Impact of Deferral/"Do Nothing" Option

Deferring this project, or replacing units on an as required basis only will result in increased risk of failure as the units age. Since these units are all of the same vintage, the risk is quite high that we will begin to experience multiple failures. The cost of emergency services for repairs and individual replacements will decrease reliability, and increase our maintenance costs. A replacement program will allow us to negotiate better pricing for both supply and installation, and allow us to much better analyse in advance, the best overall solution in terms of unit requirements.

Net Benefits of Project in Monetary Terms (where practicable)

Project #: n/a

Project Name: HVAC upgrade - 5 year replacement program

O T H E R I N F O R M A T I O N

Appendix B

Kinectrics Report

This report has been identified as being Confidential or Proprietary by the author(s). However, Oakville Hydro has received the express permission of the author(s) to submit the report to the Ontario Energy Board in support of its 2014 Cost of Service Application (EB-2013-0159). The author(s) have been advised that the report, in its entirety, will form part of the public record in this proceeding.

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R003

December 10, 2009

Kinectrics Inc.
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DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro.

Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro, & Milton Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418022-RA-0001-R003

December 10, 2009

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Revision History

Revision Number	Date	Comments	Approved
R000	October 8, 2009	Initial Draft	N/A
R001	October 28, 2009	Finalized Draft (incorporating Consortium's Comments)	N/A
R002	November 23, 2009	Finalized Report (for Consortium's final comments)	N/A
R003	December 10, 2009	Final Version	Y. Tsimberg

Table of Contents

1 Executive Summary

1.1 Introduction

One of the aspects of switching to International Financial Reporting Standards (IFRS) methodology that Ontario's Local Distribution Companies (LDCs) are embarking upon is trying to align the time period assets are amortized over with their actual useful life.

This is a rather onerous task because LDCs own and operate a large number of assets that are divided into different asset categories, each with its own degradation mechanism and useful life range. Moreover, some assets are comprised of several components that may have differing useful life than the assets themselves. It is therefore important for LDCs to properly account for the useful lives of assets and their components to facilitate conversion to IFRS.

This report reviews the useful lives of the assets, and their components that are applicable to Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro and Milton Hydro (the Consortium). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all listed in Section 35 of this Report. Useful lives of assets are dependent on a number of utilization factors (mechanical stress, electrical loading, environmental factors and operating practices) that are described in more detail in Section 1.4 of this report and it is worth noting that the useful lives of assets do not generally follow standard distribution curves as they are derived from empirical statistics.

1.2 Project Scope

This report provides an in-depth evaluation of the useful lives of the assets that are owned and operated by the Consortium members. The typical parent system(s) to which the asset belongs is provided and these "parent" systems are: *Overhead Lines* (OH), *Transmission Stations* (TS), *Municipal Stations* (MS), *Underground Systems* (UG) and *Monitoring and Control System* (S). The long term degradation mechanism of each asset category is described for each asset category and when applicable assets are sub-categorized into components: components are included when their cost is material enough and, at the same time, component could be replaced without a need to replace the whole asset. For each asset or component, the following information is presented:

- Useful Life Range
- Typical Life
- Typical time-based maintenance intervals, if applicable
- Impact of Utilization Factors

Section 1.4 provides definitions for the above terms, as well as descriptions of typical distribution system assets and asset components.

1.3 Project Execution Process

The project execution process entailed a number of steps to ensure that the industry-based information compiled by Kinectrics not only includes all the relevant assets and components used by Consortium, but also that it addresses the specific needs related to the IFRS review. The procedure is as follows:

- The initial list of assets and components was produced by the Consortium members to Kinectrics for review.
- Upon review of the initial list, Kinectrics generated an intermediate asset list that had a somewhat different background, granularity, and componentization, based on industry practices and Kinectrics experience.
- The intermediate list was reviewed jointly by the Consortium members and Kinectrics to derive a "final" list.
- For each asset and component in the "final" list, Kinectrics then gathered the information described in Section 1.2 from the sources described in Section 1.1 of this report. A Draft Report that summarized the findings and provided detail descriptions, including degradation mechanisms and applicable assumptions for each asset, was then produced.
- This Draft Report was reviewed by the Consortium members and their feedback was incorporated in the Final Report.

1.4 Definition of Terms

1.4.1 *Typical Distribution System Asset*

Typical distribution system assets include transformers, breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are rather complex systems and include a number of components.

1.4.2 *Component*

For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

- Its value is significant enough, relative to the asset value.
- A need to replace the component does not necessarily warrant replacing the entire asset.

An *asset* may be comprised of more than one component, each with an independent failure mode and degradation mechanism that may result in a substantially different useful life than the overall asset. A component may also have an independent maintenance and replacement schedule.

1.4.3 *Useful Life*

Useful Life refers to an estimated range of years during which an electric utility asset or its component is expected to operate as designed, without experiencing major functional degradation that requires major refurbishment or replacement.

In this report, the useful life range, in years, is presented in terms of a minimum, maximum, and typical value. An overwhelming number of units within a population will perform their intended design functions for a period of time greater than or equal to the *minimum* life. Conversely, an overwhelming number of units will cease to perform as designed at or beyond the *maximum* life. A majority of the population will have useful lives of around the *typical* life. For example, consider an asset class with a useful life range of 20 to 40 years, and a typical life of 30 years. An overwhelming majority of the units within this class will perform as required for at least 20 years. Very little number units will operate beyond 40 years. Finally, a majority of the units within the population will operate for approximately 30 years. Note that an asset category can have a typical life that is equal to either the maximum or minimum life. This is simply an indication that the majority of the units within a population will be operational for either the minimum or maximum years; i.e. the statistical data is skewed towards either the maximum or minimum values. The range in useful lives reflects differences in Utilization Factors described below.

1.4.4 *Typical Life*

Refers to the typical age at which the asset or component fails. This may vary depending on a utility's maintenance practices, environmental conditions, and operational stresses.

1.4.5 *Typical Time-based Maintenance Intervals*

For the purposes of this report, time-based maintenance refers to either *Routine Inspections* (RI) or *Routine Testing/Maintenance* (RTM). Other maintenance techniques such as Condition Based Maintenance, Reliability Centered Maintenance, and more intrusive periodic overhauls are very much dependent on individual utility's maintenance strategy and practices and, as such, could not be included in compiling industry-wide typical values.

Typical time-based maintenance intervals will be given only for assets that are proactively maintained, i.e. assets for which useful life is affected by regular planned maintenance. This excludes assets that are not routinely maintained.

1.4.6 *Impact of Utilization Factors*

For the purpose of this report, stress that impacts the assets refers to *Mechanical Stress* (MC), *Electrical Loading* (EL), *Environmental Conditions* (EN) and/or *Operating Practices* (OP):

- Mechanical stress includes factors such as wind and ice that leads to degradation over time

- Electrical loading refers to either constant loading that creates long term degradation or temporary overloading that may causes a severe degradation

- Environmental conditions include pollution, salt, acid rain, extreme temperature and detrimental animals (i.e. woodpeckers) that may cause degradation over time

- Operating practices refers to how frequently an asset is subject to operating procedure (automatic or manual) that impacts its useful life, e.g. reclosers operations.

Each asset could be impacted by one or more of these factors resulting in a different degradation rates for the same assets and/or components in different jurisdictions. Therefore, it is expected that some of the utility specific typical life values would be different than the ones provided in this report based on the qualitative assessment of the above factors.

1.5 Summary of Findings

Table 1-1 summarizes useful and typical lives, time based maintenance schedules, and impact of stress for Consortium assets.

Table 1-1 Summary of Componentized Assets

Report Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life (years) Minimum	Typical	Maximum	Maint. Type**	Time Based Maint. Schedule (years)	Impact of Stress***	Reference #
2	OH	Wood Poles	Pole		40	44	50	RI	15	MC, EN	[1], [2], [3], [4], [38],[39], [40]
			Cross Arm	Wood	20	40	50				
				Composite	40	60	80				
				Steel	20	70	100				
			Bracket	Galvanized Steel	20	40	50				
			Insulator	Composite	10	20	45				
				Porcelain	40	40	50				
			Anchors & Guying		20	40	50				
3	OH	Concrete Poles	*Refer to Wood Poles (1)*		50	60	60	RI	15	MC, EN	[5], [6]
4	OH	Steel Poles	*Refer to Wood Poles (1)*		60	60	80	RI	15	MC, EN	[7], [8], [41]
5	OH	Composite Poles	*Refer to Wood Poles (1)*		50	70	100	N/A	N/A	MC	[9]

* OH = Overhead Lines TS=Transmission Stations MS=Municipal Stations UG=Underground Systems S=Monitoring & Control System
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Report Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life (years) Minimum	Typical	Maximum	Maint. Type**	Time Based Maint. Schedule (years)	Impact of Stress***	Reference #
6	OH	Wires	Conductor	ACSR	50	60	77	N/A	N/A	MC, EL, EN	[5], [10]
				AAC	50	60	77				
				Cu	50	60	77				
				Insulated wire	50	60	77				
			Arrester								
7	OH	Pole Mounted Transformers	Transformer		30	40	60	N/A	N/A	EL, EN	[5]
			Arrester								
8	OH	Manual Overhead Line Switches			30	50	60	RTM	2	EL, EN	[6]
9	OH	Local Motorized Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[6]
			Motor		15	20	20				
10	OH	Remote Automated Overhead Switches	Switch		30	50	60	RTM	2	EL, EN	[11], [12]
			Motor		15	20	20				
			RTU		15	20	30				
11	OH	Fuse Cutouts			30	40	60	N/A	N/A	EL, EN	[6]
12	OH	Voltage Regulator			15	20	40	N/A	N/A	EL, EN, OP	[5], [42]

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
13	OH	Reclosers	Breaker	Vacuum	30	40	40	RTM	10	EL, OP	[5], [6], [11], [12]
				Oil	30	42	60				
			RTU		15	20	30				
14	TS	Station Service Transformers	Dry Type		20	30	40	RTM	3	EL, EN	[1],[13], [45],[46]
			Other		32	45	55				
15	TS	TS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
16	MS	MS Power Transformers	Winding		32	45	55	RTM	2	EL, EN, OP	[1], [13], [14],[15], [16],[43] [44],[48]
			Manual/Automatic On Load Tap Changer		20	20	60				
17	MS	DC Station Service	Battery bank		10	20	30	RTM	1	EL, EN, OP	[6],[17], [18],[19]
			Charger		20	20	30				
18	MS	Air Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
19	MS	Gas Insulated Switchgear	Breaker	SF6	30	42	60	RTM	6	EL, EN, OP	[1],[6], [20],[21],
				Vacuum	30	40	60				
				Air Magnetic	25	40	60				
			Switchgear assembly		40	50	60				
20	MS	Building	Building		30	50	80	RI	1	MC, EN	[13]
			Roof		15	20	20				
			Fence		30	35	45				
21	MS	Station Grounding System			25	40	50	N/A	N/A	EN	[13],[22], [23]
22	UG	UG Primary Cables	TR-XLPE	In Duct	40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
				In Concrete Encased Duct	40	40	60				
				Direct Buried	20	25	40				
			Termination		25	40	60				
			Arrester								
23	UG	UG Secondary Cables	PI (polyethylene insulated)		40	40	60	N/A	N/A	EL, EN	[6],[24], [25]
			PIJ (PVC jacket)		40	40	60				

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
24	UG	Distribution Transformer	Transformer	Pad Mounted	30	40	40	N/A	N/A	EL, EN, OP	[5],[4],[6]
				Vault	30	40	40				
				Submersible	25	35	40				
			Elbows and Inserts		20	40	60				
25	UG	Pad Mounted Switchgear	Air Insulated		20	30	40	RI	3	EL, EN, OP	[26],[27],[28]
			Gas Insulated		30	30	50				
			Solid Dielectric		30	30	50				
26	UG	Vault Switch	Metal Enclosed Switch		20	30	40	RI	3	EL, EN, OP	[6],[26],[27]
			Metal Enclosed Cutout		30	40	60				
27	UG	Utility Chamber			50	60	80	RTM	3	EN	[5],[6],[29]
28	UG	Duct	Duct Bank		30	50	80	N/A	N/A	EN	[5],[6],[30]
			Direct Buried Pipe (PVC)		30	50	75				
			HDPE		50	50	100				
29	UG	Transformer and Switchgear Foundations			30	60	80	RTM	3	EN	[5],[6]
30	UG	Junction Cubicle			25	40	50	N/A	N/A	EN	[5]
31	S	"Classic" SCADA	RTU		15	20	30	N/A	N/A	OP	[1],[11],[12],[32]
			Relay		20	30	50				
			Battery		5	10	10				

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Section #	Parent*	Asset Category	Componentization (sub category)		Useful Life Minimum	Useful Life Typical	Useful Life Maximum	Maint. Type**	Maint. Schedule	Impact of Stress***	Reference #
32	S	IED Based SCADA	IED		10	15	15	N/A	N/A	OP	[13],[32], [33]
			Battery		5	10	20				
33	S	Fault Indicators	Overhead		5	10	20	N/A	N/A	EN	[34], [47]
			Underground		10	20	30				
34	S	Metering	Meter	Residential	20	30	45	N/A	N/A	EN	[5],[35], [36]
				Industrial	20	30	60				
				Wholesale	20	30	60				
			CT		30	45	50				
			PT		30	45	50				
35	S	Smart Metering	Smart Meter		15	15	20	N/A	N/A	EN	[5],[37]
			Repeaters		5	10	15				
			Antennas								
			Data Concentrator	Sockets & Poles	10	20	20				
			Powerline Repeaters		5	10	15				
			Sky Pilot Devices								
			WAN Equipment								

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2 Wood Poles

The asset referred to in this category is the fully dressed wood pole ranging in size from 30 to 75 feet. This includes the wood pole, cross arm, bracket, insulator, and anchor & guys. Wood poles are typically the most common form of support for overhead distribution feeders and low voltage secondary lines.

The most significant component of this asset is the wood pole itself. The wood species predominately used for distribution systems are Red Pine, Jack Pine, and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

2.1 Degradation Mechanism

The end of life criteria for wood poles includes loss of strength, functionality, or safety (typically due to rot, decay, or physical damage). As wood is a natural material the degradation processes are somewhat different from those which affect other physical assets on the electricity distribution systems. The critical processes are biological, involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage.

2.2 System Hierarchy

Wood poles are considered to be a part of the Overhead Lines asset grouping.

2.3 Useful Life and Typical Life

The overall useful life of a wood pole is in the range of 40 to 50 years; the typical life is 44 years.

This asset also has several major components, each with a different useful life:

- Cross Arm (Wood, Composite, Steel)
- Bracket (Galvanized Steel)
- Insulator (Composite, Porcelain)
- Anchor and Guying

2.3.1 *Cross Arm*

The useful life of a wood cross arm is in the range of 20 to 50 years; the typical life is 40 years.

The useful life of a composite cross arm is in the range of 40 to 80 years; the typical life is 60 years.

The useful life of a steel cross arm is in the range of 20 to 100 years; the typical life is 70 years.

2.3.2 *Bracket (Galvanized Steel)*

The useful life of an aluminum bracket component ranges from 20 to 50 years, with a typical value of approximately 40 years.

2.3.3 *Insulator*

The useful life of a composite insulator is in the range of 10 to 45 years; the typical life is 20 years.

The useful life of a porcelain insulator is in the range of 40 to 50 years, with a typical life of 40 years.

2.3.4 *Anchors and Guying*

The useful life of anchors and guying is in the range of 20 to 50 years; the typical life is 40 years.

2.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

2.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

3 Concrete Poles

This asset category includes the concrete pole with the same components as for the wood poles, namely cross arm, bracket, insulator, and anchor. These poles range in size from 35 to 80 feet, with the typical pole being 60 feet.

3.1 Degradation Mechanism

The most significant component in this class is the concrete pole itself. Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in), however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice, resulting in cracking and separation of the concrete. The spun concrete process used in manufacturing poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

3.2 System Hierarchy

Concrete poles are considered to be a part of the Overhead Lines assets grouping.

3.3 Useful Life and Typical Life

The useful life range of the concrete pole component is 50 to 60 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

3.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

3.5 Impact of Utilization Factors

The useful life of this asset is impacted by Mechanical Stress and Environmental Conditions.

4 Steel Poles

This asset category includes the directly buried steel pole, cross arm, bracket, insulator, and anchor.

4.1 Degradation Mechanism

The degradation of directly buried steel poles is mainly due to steel corrosion in-ground. In-ground situations are vastly different because of the wide local variations in soil chemistry, moisture content and conductivity that will affect the way coated or uncoated steel will perform in the ground.

There are two issues that determine the life of buried steel. The first is the life of the protective coating and the second is the corrosion rate of the steel. The item can be deemed to have failed when the steel loss is sufficient to prevent the steel performing its structural function. Where polymer coatings are applied to buried steel items, the failures are rarely caused by general deterioration of the coating. Localized failures due to defects in the coating, pin holing or large-scale corrosion related to electrolysis are common causes of failure in these installations.

Metallic coatings, specifically galvanizing, and to a lesser extent aluminum, fail through progressive consumption of the coating by oxidation or chemical degradation. The rate of degradation is approximately linear, and with galvanized coatings of known thickness, the life of the galvanized coating then becomes a function of the coating thickness and the corrosion rate.

4.2 System Hierarchy

Steel poles are considered a part of the Overhead Lines asset grouping.

4.3 Useful Life and Typical Life

The useful life of steel poles is in the range of 60 to 80 years; the typical life is 60 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

4.4 Time Based Maintenance Intervals

A typical routine inspection interval for this asset is every 15 years.

4.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress and Environmental Conditions.

5 Composite Poles

This asset category includes the composite pole, cross arm, bracket, insulator, and anchor. At Consortium the composite poles are fiberglass.

5.1 Degradation Mechanism

The most significant component in this class is the composite pole itself. The major degradation of composite poles is ultra violet (UV) degradation. It represents an attack from ultra-violet radiation, which might result in crack or disintegration in composite poles. It is a common problem in products exposed to sunlight. Continuous exposure is a more serious problem than intermittent exposure, since attack is dependent on the extent and degree of exposure. In fiber products like composite poles, useful life will be shortened because the outer fibers will be attacked first, and will easily be damaged by abrasion. This will end up with fiber blooming and fading.

5.2 System Hierarchy

Composite poles are considered to be a part of the Overhead Lines assets grouping.

5.3 Useful Life and Typical Life

The useful life range of the composite pole component is 50 to 100 years; the typical life is 70 years. For other components, (cross arm, bracket, insulator, and anchor), please refer to Section 2.3.

5.4 Time Based Maintenance Intervals

. Composite poles are not subject to planned maintenance.

5.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress.

6 Wires

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy either directly to large customers or from Municipal Stations via distribution transformers to the end users. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

The overhead conductors typically used by the Consortium are aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), copper, and insulated wire.

6.1 Degradation Mechanism

To function properly, conductors must retain both their conductive properties and mechanical (i.e. tensile) strength. Aluminum conductors have three primary modes of degradation: corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor, as well as environmental and operating conditions. Most utilities find that corrosion and fatigue present the most critical forms of degradation.

Generally, corrosion represents the most critical life-limiting factor for aluminum-based conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations.

Fatigue degradation presents greater detection and assessment challenges than corrosion degradation. In extreme circumstances, under high tensions or inappropriate vibration or galloping control, fatigue can occur in very short timeframes. However, under normal operating conditions, with proper design and application of vibration control, fatigue degradation rates are relatively slow. Under normal circumstances, widespread fatigue degradation is not commonly seen in conductors less than 70 years of age. Also, in many cases detectable indications of fatigue may only exist during the last 10% of a conductor's life.

In designing transmission lines, engineers ensure that conductors receive no more than 60% of their rated tensile strength (RTS) during heaviest anticipated weather loads. The tensile strength of conductors gradually decreases over time. When conductors experience unexpectedly large mechanical loads and tensions beyond 50% of their RTS, they begin to undergo permanent stretching with noticeable increases in sagging.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. After a loss of 10% of a conductor's RTS, significant sag occurs, requiring either resagging or replacement of the conductor.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminum strands, reducing strength at those sites and potentially leading to conductor failures. Visual inspection readily detects arcing damage.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

The degradation of copper wire is mostly due to corrosion. Oxidization gives copper a high resistance to corrosion. Derivatives of chlorine and sulfur contained in coastal atmospheres start the oxidation by forming a blackish or greenish film. The film is very dense, has low solubility, high electric resistance and high resistance to the chemical attack and to corrosion. Despite this, mechanical vibrations, abrasion, erosion and thermal variations may cause fissures and faults in this layer. When this happens, the metal is uncovered and corrosion may occur. Also electrolytes with low Cl contents could enter, causing a dislocation of the passivity. This may also be the result of a deficit of oxygen which would make the area anodic.

6.2 System Hierarchy

The Wire asset category belongs to the Overhead Lines assets grouping.

6.3 Useful Life and Typical Life

The useful life of conductors is in the range of 50 to 77 years; the typical life is 60 years.

6.4 Time Based Maintenance Intervals

Overhead conductors are not subject to planned maintenance.

6.5 Impact of Utilization Factors

This asset is impacted by Mechanical Stress, Electrical Loading and Environmental Conditions.

7 Pole Mounted Transformers

Distribution pole top mounted transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

7.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

7.2 System Hierarchy

The Pole Mounted Transformer asset category belongs to the Overhead Lines assets grouping.

7.3 Useful Life and Typical Life

The useful life of the pole mounted transformer is in the range of 30 to 60 years, with a typical value close to 40 years.

7.4 Time Based Maintenance Intervals

Pole mounted distribution transformers are not subject to planned maintenance.

7.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

8 Manual Overhead Line Switches

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang.

8.1 Degradation Mechanism

The main degradation processes associated with manually operated line switches include the following, with rate and severity depending on operating duties and environment:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

8.2 System Hierarchy

Overhead Switches asset category belongs to the Overhead Lines assets grouping.

8.3 Useful Life and Typical Life

The useful life of manually operated switches is in the range of 30 to 60 years; the typical life is 50 years.

8.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for manually operated overhead switches is two years.

8.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

9 Local Motorized Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches and a motor. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism is controlled by a motor.

9.1 Degradation Mechanism

Like the remotely operated switch, the main degradation processes associated with local motorized overhead switches include the following:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of degradation are a function on operating duties and environment.

9.2 System Hierarchy

Local Motorized Overhead Switches category belongs to the Overhead Lines assets grouping.

9.3 Useful Life and Typical Life

The local motorized overhead switch can be componentized into two components:

- Switch
- Motor

9.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead switch in section 8.3 of this report).

9.3.2 *Motor*

The useful life of the motor of local motorized switches is in the range of 15 to 20 years; the typical life is about 20 years.

9.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for local motorized switches is every two years.

9.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

10 Remote Automated Overhead Line Switches

This asset class consists of overhead line three-phase, gang operated switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of the switches are rated for load interruption, others are designed to operate under no load conditions and operate only when the current through the switch is zero. Most distribution line switches are rated 600 to 900 A continuous rating. Switches when used in conjunction with cutout fuses provide short circuit interruption rating. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in open position. This component also consists of a remote terminal unit (RTU) component.

10.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates. Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out, the switch operating mechanism may seize making the disconnect switch inoperable. In addition, when blades fall out of alignment, excessive arcing may result. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

10.2 System Hierarchy

Remote Automated Overhead switches asset category belongs to the Overhead Lines assets grouping.

10.3 Useful Life and Typical Life

The remote automated overhead switch can be componentized into three components:

- Switch
- Motor
- Remote Terminal Unit (RTU)

10.3.1 *Switch*

The useful life of the switch is in the range of 30 to 60 years; the typical life is 50 years (the same as for Manually Operated Overhead Switch in section 8.3 of this report).

10.3.2 *Motor*

The useful life of a motor is in the range of 15 to 20 years; the typical life is 20 years (the same as for Local Motorized Overhead Switch in section 9.3.2 of this report).

10.3.3 *Remote Terminal Unit (RTU)*

The useful life of an RTU is in the range of 15 to 30 years; the typical life is 20 years.

10.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for remote automated overhead switches is every two years.

10.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

11 Fuse Cutouts

This asset is applied on overhead transformers, capacitors, cables or lines. Fuse Cutouts will interrupt all faults including low current that will melt the fuse link and high rated interrupting current so long as the system is under realistic transient-recovery-voltage conditions.

11.1 Degradation Mechanism

The major degradation of fuse cutouts is on fuse body. There are several degradation modes in practice including the production of carbon from organic materials in the fuse, generation of water vapor to assist current interruption and electrical breakdown in high stress areas of the core.

The production of carbon from organic materials in the fuse body is one degradation mode in practice. This carbon is not produced until a particular body temperature is reached, and the time for this to occur depends on the fuse design. The most critical factors would appear to include the heat generated in the fulgurite, the distance between the fulgurite and the fuse body, the thermal conductivity of the filler material, and the breakdown temperature of the organic material.

For some fuses that generate water vapor to assist current interruption, the water is deposited on the inside surface of the body. Treeing is observed on the surface, ultimately leading to a steady increase in leakage current until failure.

For the fuse cores that contain organic material, hollow core is developed at high temperature due to release of water molecules, resulting in electrical breakdown in high stress areas of the core in certain designs.

11.2 System Hierarchy

Fuse Cutouts asset category belongs to the Overhead Lines assets grouping.

11.3 Useful Life and Typical Life

The useful life of fuse cutouts is in the range of 30 to 60 years; the typical life is 40 years.

11.4 Time Based Maintenance Intervals

Fuse Cutouts are not subject to planned maintenance

11.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

12 Voltage Regulators

Voltage regulators are static devices that perform step-up and step-down voltage change operations. Distribution line transformers change the medium or low distribution voltage to 120/240 V or other common voltages for use in residential and commercial applications.

12.1 Degradation Mechanism

It has been demonstrated that the life of the voltage regulator's internal insulation is related to temperature-rise and duration. Therefore, voltage regulator life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of voltage regulators.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of voltage regulator that should be selected for a given number and type of customers to obtain optimal life. There is also the operating practices affect on voltage regulators. If it is a strong system, the voltage regulator may not need to step-up or step-down the voltage, in which case there would be less stress on the device itself.

12.2 System Hierarchy

Voltage Regulators asset category belongs to the Overhead Lines assets grouping.

12.3 Useful Life and Typical Life

The useful life of voltage regulators is in the range of 15 to 40 years; the typical life is 20 years.

12.4 Time Based Maintenance Intervals

Voltage Regulators are not subject to planned maintenance.

12.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

13 Reclosers

This asset class consists of light duty circuit breakers equipped with interrupters that use controllers. This is where the breaking and making of fault current takes place. The interrupters use oil of vacuum as the insulating agent. The controllers are either hydraulic or electric. It is designed for single phase or three phase use, depending on the model.

13.1 Degradation Mechanism

The degradation processes associated with reclosers involves the effects of making and breaking fault current, the mechanism itself and deterioration of components. The effects of making and breaking fault current affect suppression devices as well as the contacts, the oil, and the arc control. The degradation of these devices depends on the prevailing fault, if it is well below the rated capability of the recloser, the deteriorating effects will be small. For the mechanism itself, deterioration or mal-operation of the mechanism causes deterioration during operation. Typically lack of use, corrosion and poor lubrication are the main causes of mechanism mal-function. For deterioration, exposure to weather is a potentially significant degradation process – primarily corrosion of the tank and other metallic components and deterioration of bushings.

13.2 System Hierarchy

Recloser asset category belongs to the Overhead Lines assets grouping.

13.3 Useful Life and Typical Life

Reclosers can be categorized into two components:

- Breaker (Vacuum, Oil)
- RTU

13.3.1 *Breaker*

The useful life of <u>Vacuum</u> breakers is in the range of 30 to 40 years; the typical life is 40 years.

The useful life of <u>Oil</u> breakers is in the range of 30 to 60 years; the typical life is 42 years.

13.3.2 *RTU*

The useful life of recloser RTUs is in the range of 15 to 30 years; the typical life is 20 years.

13.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for the breaker component of reclosers is every ten years.

13.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Operating Practices.

14 Station Service Transformers

The station service transformers are the small transformers are configured to provide power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the distribution station. The most reliable source of such power is directly from the transmission or distribution lines. This report refers to both to both dry type and other types of transformers.

14.1 Degradation Mechanism

As with most transformers, end of life is typically a result of insulation failure, particularly paper insulation. The oil and paper insulation degrade as oxidation takes place in the presence of oxygen, high temperature, and moisture. Acids, particles, and static electricity also have degrading effects to the insulation.

For dry type transformers, the major degradation factors are dirt and moisture. Dirt will contaminate insulation surfaces allowing the formation of conductive paths along the surfaces and eventually to ground. In the case of ventilated dry type transformers, the windings are in direct contact with the air. External air-carrying contaminants or excessive moisture could reduce winding insulation. Dust and dirt accumulation can also reduce air circulation through windings, which eventually shorten the life expectancy of a dry type transformer.

14.2 System Hierarchy

Station service transformers are considered part of the Transmission Stations assets grouping.

14.3 Useful Life and Typical Life

The useful life of a station service transformer is based on the transformer type:

- Dry Type
- Other

14.3.1 *Dry Type*

The useful life of dry type station service transformers is in the range of 20 to 40 years; the typical life is 30 years.

14.3.2 *Other*

The useful life of other station service transformers is in the range of 32 to 55 years; the typical life is 45 years.

14.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is three years.

14.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions. If this device is running within an electrically stable system there will be less stress imposed on it.

15 TS Power Transformers

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, ratings may range from 30MVA to 125 MVA. The Consortium typically uses TS Power Transformers rated 75/125 MVA.

15.1 Degradation Mechanism

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. They are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures, through-faults can cause displacement of coils and insulation, and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are complex mechanical devices and are therefore prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

15.2 System Hierarchy

Power Transformers belong to the Transformer Stations assets grouping.

15.3 Useful Life and Typical Life

This asset could be componentized into the following components:

- Winding
- Manual/Automatic On Load Tap Changer

15.3.1 *Winding*

The useful life of the winding can be in the range of 32-55 years, depending on the loading condition and ambient operating temperature, and routine maintenance practices. A typical life of 45 years can be expected for the winding system.

15.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic on load tap changer, assuming it is vacuum type, is 20-60 years; the typical life is 20 years.

15.4 Time Based Maintenance Intervals

For TS power transformers, the typical routine testing/maintenance interval is two years.

15.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

16 MS Power Transformers

Power transformers at distribution stations typically step down voltage to distribution levels. Ratings typically range from 5 MVA to 30 MVA. The Consortium typically uses MS Power Transformers rated 20/33.3 MVA.

16.1 Degradation Mechanism

The degradation of the power transformers at municipal stations or at customer sites is similar to that of the transformers at transmission stations. These transformers are subject to electrical, thermal, and mechanical aging. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

16.2 System Hierarchy

MS Power Transformer asset category belongs to the Municipal Stations assets grouping.

16.3 Useful Life and Typical Life

The power transformer also has major components that have different useful lives. Componentization is as follows:

- Winding
- Manual/Automatic On Load Tap Changer

16.3.1 *Winding*

The useful life of windings is 32 to 55 years; the typical life is 45 years.

16.3.2 *Manual/Automatic On Load Tap Changer*

The useful life range of the manual or automatic tap changer, assuming it is vacuum type, is 20 to 60 years; the typical life is 20 years.

16.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is two years.

16.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the on load tap changer component that is affected by operating practices. If this device is running within an electrically sound system there will be less stress imposed on it.

17 DC Station Service

The DC station service asset class includes battery banks and chargers. Equipment within transmission and municipal stations must be provided with a guaranteed source of power to ensure they can be operated under all system conditions, particularly during fault conditions. There is no known way to store AC power so the only guaranteed instantaneous power source must be DC, based on batteries.

17.1 Degradation Mechanism

Effective battery life tends to be much shorter than many of the major components in a station. The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

It is well understood in the utility industry that regular inspection and maintenance of batteries and battery chargers is necessary. In most cases the explicit reason for carrying out regular maintenance inspection is to detect minor defects and rectify them. However, critical examination of trends in maintenance records can give an early warning of potential failures.

Despite the regular and frequent maintenance and inspection of battery systems, failures in service are still relatively frequent. For this reason, many utilities employ battery monitors and alarm systems. The earlier versions of these are still widely used and are relatively unsophisticated devices that measure basic battery parameters with pre-set alarm levels. More modern monitoring devices have the ability to identify a potential failure as it develops and to provide a warning.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. Batteries consist of multiple individual cells. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery.

Battery chargers are also critical to the satisfactory performance of the whole battery system. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the batteries themselves. Nevertheless, problems do occur. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it would be normal to replace the battery charger.

17.2 System Hierarchy

DC station services belong to Municipal Stations assets grouping.

17.3 Useful Life and Typical Life

This asset also has two major components that have differing useful lives:

- Battery Banks
- Charger

17.3.1 *Battery Bank*

The battery bank has a useful life range of 10 to 30 years; typical life is 20 years.

17.3.2 *Charger*

The charger has a useful life range of 20 to 30 years; typical life is 20 years.

17.4 Time Based Maintenance Intervals

Typically, routine testing/maintenance for batteries are conducted annually. The maintenance of schedule battery chargers is typically coordinated with that of the battery.

17.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. This device cannot be overloaded, last longer when there is not extreme cold weather conditions and only the battery bank component is affected by operating practices (i.e., it only runs if the AC fails).

18 Air Insulated Switchgear

Air Insulated Switchgear consists of an assembly of retractable/racked switchgear devices that are totally enclosed in a metal envelope (metal-enclosed). These devices operate in the medium voltage range, from 4.16 to 44 kV. The switchgear includes breakers; disconnect switches, or fusegear, current transformers (CTs), voltage transformers (VTs) and occasionally some or all of the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. The gear is modular in that each breaker is enclosed in its own metal envelope (cell). The gear also is compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and bus-bars associated with each cell.

18.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor. However the degradation mechanism differs slightly between switchgear types: air insulated and gas insulated.

Correct operation of the mechanism is critical in devices that make or break fault currents, i.e. the contact opening and closing characteristics must be within specified limits. The greatest cause of mal-operation of switchgear is related to mechanism malfunction. Deterioration due to corrosion or wear due to lubrication failure may compromise mechanism performance by either preventing or slowing down the operation of the breaker. This is a serious issue for all types of switchgear.

In older air filled equipment, degradation of active solid insulation (for example drive links) has been a significant problem for some types of switchgear. Some of the materials used in this equipment, particularly those manufactured using cellulose-based materials (pressboard, SRBP, laminated wood) are susceptible to moisture absorption. This results in a degradation of their dielectric properties that can result in thermal runaway or dielectric breakdown. An increasingly significant area of solid insulation degradation relates to the use of more modern polymeric insulation. Polymeric materials, which are now widely used in switchgear, are very susceptible to discharge damage. These electrical stresses must be controlled to prevent any discharge activity in the vicinity of polymeric material. Failures of relatively new switchgear due to discharge damage and breakdown of polymeric insulation have been relatively common over the past 15 years.

Temperature, humidity and air pollution are also significant degradation factors, so indoor units tend to have better long-term performance. The safe and efficient operation of switchgear and its longevity may all be significantly compromised if the substation environment is not adequately controlled. In addition, the air switchgear can tolerate less number of full fault operations before maintenance is required.

18.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

18.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

18.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

18.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

18.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

18.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

19 Gas Insulated Switchgear

The latest design of metalclad gear is the Gas Insulated Switchgear (GIS), which uses low-pressure SF6 gas as a general insulation medium, as a replacement for the air. The insulation within the metal enclosure is not necessarily the same as the working fluid in the breakers themselves, which presently is either SF6 or vacuum.

19.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor. However the degradation mechanism differs slightly between switchgear types: air insulated and gas insulated.

Generally, mechanism malfunction causes most operational problems in GIS. Corrosion and lubrication failure may compromise mechanism performance by preventing or slowing its operation.

Solid insulation such as that in entrance bushings, internal support insulators, plus breaker and switch operating rods have caused many GIS failures. Manufacturing, shipping, installing, maintaining and operating the GIS can cause defects in the insulation. Defects include voids in epoxy insulators, delamination of epoxy and metallic hardware, and protrusions on conductors. In floating components, fixed and moving particles can lead to failures. Partial discharge (PD) activity usually leads to flashovers.

Corrosion and general deterioration increase risks of moisture ingress and SF6 leaks, particularly in outdoor GIS. If not treated, these factors may cause the end-of-life for GIS.

GIS is designed and manufactured for outdoor use, but it generally has better long-term performance when installed indoors. Outdoor GIS, particularly older ITE designs, have higher than acceptable SF6 gas leaks because of the poor quality of fittings, connectors, valves, by-pass piping, general enclosure porosity and flange corrosion. Indoor installations reduce problems from corrosion, moisture ingress, low ambient temperatures and SF6 leaks.

GIS have more costly, difficult and time-consuming post fault maintenance requirements than air insulated switchgear. Older GIS have even more post-fault maintenance problems. Accessibility, fault location, fault level and duration, degree of compartmentalization, isolation requirements, pressure relief, burn-through protection, parts and service capabilities all help determine post-fault maintenance needs.

19.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

19.3 Useful Life and Typical Life

This asset also has several major components, each with a different useful life:

- Breaker (SF6, Vacuum, Air Magnetic)
- Switchgear Assembly

19.3.1 *Breaker*

The useful life range of SF6 type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

19.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

19.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is six years.

19.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. It is specifically the breaker component that is affected by operating practices. If this device is running within an electrically system there will be less stress imposed on it. It is specifically the switchgear assembly component that is affected by environmental factors, specifically temperature.

20 Building

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work. This asset includes the building itself (foundations, walls), roof, and fence.

20.1 Degradation Mechanism

The following contribute to the degradation of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements
- Environmental concerns
- Functional requirements

Buildings are a very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life. Rather impacts such as environmental rain, wind and snow storms contribute highly to the degradation of buildings. It is the potential water ingress with poses the most danger to the asset due to the presence of electrical equipment. In order to prevent this, the buildings must be weatherproof.

Also, since the foundation materials typically consist of reinforced concrete designed to consider environmental elements including soil conditions and climate. Landscaping is used to control soil erosion, maintain site cleanliness and facilitate an efficient and safe work environment.

Preventative maintenance helps ensure long-term integrity of buildings. This type of maintenance should be done on a regular basis. As well the occasional refurbishment of doors, windows and roofs helps with the viability of the building.

The building roof is the most susceptible to degradation due to environmental factors. The roof is typically level and composed of tar and an aggregate that is designed to keep the wind from wearing at the tar. Nevertheless, the roof is still susceptible to environmental degradation and if not sealed properly can become a source of flooding. The maintenance of the roof is generally the largest undertaking for buildings.

20.2 System Hierarchy

Building asset category belongs to the Municipal Stations assets grouping.

20.3 Useful Life and Typical Life

The overall useful life range of the building itself is 30 to 80 years; the typical life is 50 years.

This asset also has two other major components, each of which has a different useful life. From a maintenance practice perspective, the building can be componentized into the following:

- Roof
- Fence

20.3.1 *Roof*
The useful life of the roof can be in the range of 15 to 20 years, with a typical life of 20 years.

20.3.2 *Fence*
The useful life range of the fence is 30 to 45 years, with a typical life of 35 years.

20.4 Time Based Maintenance Intervals
The typical routine inspection interval for this asset is every year.

20.5 Impact of Utilization Factors
This asset is impacted by Mechanical Stress and Environmental Conditions.

21 Station Grounding System

The station grounding system asset refers to grounding rods and connectors. Grounding systems in stations dissipate maximum ground fault currents without interfering with power system operation or causing voltages dangerous to people or equipment. Safety hazards from inadequate grounding include excessive ground potential rises and excessive step and touch potentials. Generally, grounding system assets provide suitable paths for ground currents to follow from power equipment and conductors into the earth. Consequently, complete grounding systems include buried conductors, ground rods and connections, plus soil and vegetation in the area. Soil and vegetative conditions affect water retention and drainage, which impact overall performance of the grounding system.

21.1 Degradation Mechanism

Station grounding systems keep ground potential rise, step and touch potentials below specified limits when maximum (i.e. worst case) ground faults occur. Under fault conditions, the following factors determine step and touch potentials:

- Magnitude of the fault current
- Resistance of ground combined with the ground grid consisting of station electrodes, transmission line sky wires and distribution neutrals
- Ground resistivity of upper and lower layers of earth.

Increases in system capacity and fault currents at a station may lead to unacceptable performance of the ground grid. Corrosion of buried conductors and connectors, mechanical damage to buried electrodes, plus burning-off of grounding conductors and connectors during heavy fault currents also may lead to unsatisfactory performance. Further, changes in resistivity of upper or lower layers of earth may adversely affect ground grid characteristics.

21.2 System Hierarchy

Station Grounding Systems asset category belongs to the Municipal Stations assets groupings.

21.3 Useful Life and Typical Life

Station grounding systems have a useful life range of 25 to 50 years; the typical life is 40 years.

21.4 Time Based Maintenance Intervals

Station Grounding Systems are not subject to planned maintenance.

21.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

22 Underground Primary Cables

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. The initial capital cost of a distribution underground cable circuit is three or more times the cost of an overhead line of equivalent capacity and voltage. The cross linked polyethylene (XLPE) cable is the type of underground distribution cables used by Consortium. While XLPE underground cable can be installed in ducts (and concrete enclosed ducts), it can also be directly buried.

Cable terminations are designed to separate the cable ground from the conductor in a safe and controlled manner. Inside the cable, ground and high voltage are separated by only a few millimeters. This distance is much too small to support any voltage. Therefore the termination must increase this separation while being able to withstand the surrounding environment.

22.1 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This is assumed to be the reason for poor reliability and relatively short lifetimes of early polymeric cables. As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved.

The major degradation problems with the cable terminations concern mostly flashover and tracking associated with the outside and interior surfaces of the accessory. However, there are also problems of overheating at connections and voltage control at the end of the cable shield.

22.2 System Hierarchy

Underground Primary Cables asset category belongs to the Underground Systems assets grouping.

22.3 Useful Life and Typical Life

The overall useful life range of the cable itself is dependent on the cable type and component:

- TR-XLPE (In Duct, In Concrete Encased Duct, Direct Buried)
- Termination

22.3.1 *TR-XLPE*

The useful life range of in duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of in concrete encased duct cable is 40 to 60 years; the typical life is 40 years.

The useful life range of direct buried cable is 20 to 40 years; the typical life is 25 years.

22.3.2 *Termination*

The useful life range of termination component of underground cable is 25 to 60 years; the typical life is 40 years.

22.4 Time Based Maintenance Intervals

Underground Primary Cables are not subject to planned maintenance.

22.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

23 Underground Secondary Cables

Secondary underground cables are used to supply customer premises. The Polyethylene Insulated (PI) and PVC Jacket (PIJ) are similar to the XLPE cables described above, and are assumed to be in duct.

23.1 Degradation Mechanism

Underground secondary conductors are typically insulated with polyethylene. Polyethylene insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. These commissioning tests are an area of some concern for polyethylene cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables. However those with the PVC jacket have further insulation to prevent some deterioration of the insulation.

23.2 System Hierarchy

Underground Secondary Cables are used in the Underground system.

23.3 Useful Life and Typical Life

The underground secondary cable can be categorized into two types:

- Polyethylene Insulated
- PVC Jacket

23.3.1 *Polyethylene Insulated*

The useful life range of in polyethylene insulated cable is 40 to 60 years; the average life is 40 years.

23.3.2 *PVC Jacket*

The useful life range of in PVC jacket cable is 40 to 60 years; the average life is 40 years.

23.4 Time Based Maintenance Intervals

Underground Secondary Cables are not subject to planned maintenance

23.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading and Environmental Conditions.

24 Distribution Transformer

This asset class consists of the transformer and elbows and inserts associated with the system. There are three types of transformers that Consortium uses: Pad Mounted, Vault and Submersible.

Pad mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. Vault transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil. Submersible transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil.

24.1 Degradation Mechanism

The pad-mounted transformer has a similar degradation mechanism to other distribution transformers. It has been demonstrated that the life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

In general, the following are considered when determining the health of the pad-mounted transformer:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs, etc.
- Transfer operating age and winding temperature profile

The vault transformer and submersible transformer have a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges has strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

24.2 System Hierarchy

Distribution Transformers asset category belongs to the Underground Systems asset grouping.

24.3 Useful Life and Typical Life

The overall useful life range of the transformer itself is dependent on the component:

- Transformer (Pad Mounted, Vault, Submersible)
- Elbows and Inserts

24.3.1 *Transformer*

The useful life range of pad mounted distribution transformers are 30 to 40 years; the typical life is 40 years.

The useful life range of vault distribution transformers is 30 to 40 years; the typical life is 40 years.

The useful life range of submersible distribution transformers is 25 to 40 years; the typical life is 35 years.

24.3.2 *Elbows and Inserts*

The useful life range of the elbows and inserts component of distribution transformers is 20 to 60 years; the typical life is 40 years.

24.4 Time Based Maintenance Intervals

Distribution Transformers are not subject to planned maintenance.

24.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices. The operating practices impact only the elbows and inserts component of the asset.

25 Pad Mounted Switchgear

Pad-mounted switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, SF6 load break switches and vacuum fault interrupters. A majority of the pad mounted switchgear currently employs air-insulated gang operated load-break switches.

25.1 Degradation Mechanism

The pad-mounted switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures or ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism and degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO_2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

25.2 System Hierarchy

Pad-Mounted Switchgear belongs to the Underground Systems assets grouping.

25.3 Useful Life and Typical Life

The overall useful life range of the switchgear itself is dependent on the pad mount switchgear type:

- Air Insulated
- Gas Insulated
- Solid Dielectric

25.3.1 *Air Insulated*

The useful life range of this air insulated pad mount switchgear is 20 to 40 years; the typical life is 30 years.

25.3.2 *Gas Insulated*

The useful life range of this gas insulated pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.3.3 *Solid Dielectric*

The useful life range of this solid dielectric pad mount switchgear is 30 to 50 years; the typical life is 30 years.

25.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is three years.

25.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

26 Vault Switch

The vault switches used by Consortium are metal enclosed switch and metal enclosed cutout. These units are essentially pad mounted switchgear, enclosed in stainless steel containers, with the ability to be wall or ceiling mounted.

26.1 Degradation Mechanism

The degradation mechanism of this asset is similar to that of other types of pad mounted switchgear. Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

26.2 System Hierarchy

Vault Switches asset category belongs to the Underground Systems assets grouping.

26.3 Useful Life and Typical Life

The overall useful life range of the vault switch is dependent on the pad mount switchgear type:

- Metal Enclosed Switch
- Metal Enclosed Cutout

26.3.1 *Metal Enclosed Switch*

The useful life range of metal enclosed switch is 20 to 40 years; the typical life is 30 years.

26.3.2 *Metal Enclosed Cutout*

The useful life range of metal enclosed cutout is 30 to 60 years; the typical life is 40 years.

26.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is 3 years.

26.5 Impact of Utilization Factors

This asset is impacted by Electrical Loading, Environmental Conditions and Operating Practices.

27 Utility Chamber

Utility Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. They come in different styles, shapes and sizes according to the location and application. Pre-cast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are less expensive to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems.

27.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, utility chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, utility chamber chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Utility chamber degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Utility chamber systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a utility chamber system. Similarly, utility chamber systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with utility chambers also requires evaluation in assessing the overall condition of a utility chamber system.

27.2 System Hierarchy

Utility Chambers asset category belongs to the Underground Systems assets grouping.

27.3 Useful Life and Typical Life

Utility chambers have a useful life range of 50 to 80 years; the typical life range is 60 years.

27.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

27.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

28 Duct

In areas such as road crossings, ducts provide a conduit for underground cables to travel. They are comprised of a number of ducts, in trench, and typically encased in concrete. Ducts are sized as required and are usually two to six inches in diameter.

28.1 Degradation Mechanism

The ducts connecting one utility chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a utility chamber that is otherwise in sound condition is a good indicator of a failure of a portion of the ductwork. Since there are no specific tests that can be conducted to determine duct integrity at reasonable cost, the duct system is typically treated on an ad hoc basis and repaired or replaced as is determined at the time of cable replacement or failure.

28.2 System Hierarchy

Ducts asset category belongs to the Underground Systems assets grouping.

28.3 Useful Life and Typical Life

The overall useful life range of the duct is dependent on the type:

- Duct Bank
- Direct Buried Pipe (PVC)
- High Density Polyethylene (HDPE)

28.3.1 *Duct Bank*

The useful life range of the duct bank type is 30 to 80 years; the typical life is 50 years.

28.3.2 *Direct Buried Pipe (PVC)*

The useful life range of the direct buried pipe type is 30 to 75 years; the typical life is 50 years.

28.3.3 *High Density Polyethylene (HDPE)*

The useful life range of the HDPE type is 50 to 100 years; the typical life is 50 years.

28.4 Time Based Maintenance Intervals

Ducts are not subject to planned maintenance.

28.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

29 Transformer and Switchgear Foundations

This asset class is similar to the utility chamber asset. It is a buried pre cast concrete vault on which pad-mounted transformers or switchgear are mounted. The foundation itself is buried; however the top portion is above ground.

29.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, transformer and switchgear foundation must withstand heavy loads associated with traffic in the boulevard. When located in driving lanes, concrete vault must match street grading. Since vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Transformer and switchgear foundation degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Transformer and switchgear foundation also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a transformer and switchgear foundation. Similarly, transformer and switchgear foundation with lights that do not function properly constitute defective systems.

29.2 System Hierarchy

Transformer and Switchgear foundations asset category belongs to the Underground Systems assets grouping.

29.3 Useful Life and Typical Life

The overall useful life range of Transformer and switchgear foundation is 30 to 80 years; the typical life is 60 years.

29.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

29.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

30 Junction Cubicle

This asset class consists of a wiring box similar to pad mount switchgear. For the purposes of this study there is only reference to junction casing.

30.1 Degradation Mechanism

The main degradation associated with the junction cubicle casing is caused by outside sources. These include corrosion, vehicle damage, case rusting, and dirt or contamination.

30.2 System Hierarchy

Junction cubicle is used in the Underground Systems assets grouping.

30.3 Useful Life and Typical Life

The overall useful life range of junction cubicle casing is 25 to 50 years; the typical life is 40 years.

30.4 Time Based Maintenance Intervals

Junction Cubicles are not subject to planned maintenance

30.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

31 "Classic" SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

31.1 Degradation Mechanism

There are many factors that contribute to the end-of-life of RTUs. Utilities may choose to upgrade or replace older units that are no longer supported by vendors or where spare parts are no longer available. Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution, and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

31.2 System Hierarchy

Classic SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

31.3 Useful Life and Typical Life

This asset has several major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- RTU
- Relay
- Battery

31.3.1 *RTU*

The useful life of the RTU in "classic" SCADA is in the range of 15 to 30 years; the typical life is 20 years.

31.3.2 *Relay*

The useful life of the relay in "classic" SCADA is in the range of 20 to 50 years; the typical life is 30 years.

31.3.3 *Battery*

The useful life of the battery in "classic" SCADA is in the range of 5 to 10 years; the typical life is 10 years.

31.4 Time Based Maintenance Intervals

"Classic" SCADA is not subject to planned maintenance.

31.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery and relay components that are affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

32 IED Based SCADA

Intelligent Electronic Devices (IED) based Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility.

32.1 Degradation Mechanism

Physical degradation of IED Based SCADA happens on hardware part of an IED. Compared to solid state relays, IEDs are not sensitive to ambient environment. The major contributing factor of degradation is the electrical environment, i.e. inrush transient. Since IEDs have built-in self-supervision system, the settings with perfect long time stability is guaranteed.

The failure mode of an IED can be:

- Fail to trip because communication port is held by defective external equipment
- Mal-function due to hardware/firmware/software version mismatch
- Mal-function due to software design flaw causing software latched by external EMI interference
- Will not operate due to power supply failure

To assess the health status of an IED, the following condition parameters are studied:

- Operating mechanism, including power supply, insulation, connection
- Recalibration, including recalibration record and relay functionality (e.g., overcurrent, distance etc.)
- Reliability, including mal-operation count, loading and age

32.2 System Hierarchy

IED Based SCADA asset category belongs to the Monitoring and Control Systems assets grouping.

32.3 Useful Life and Typical Life

This asset has two major components, each of which has a different useful life. From a maintenance practice perspective, classic SCADA can be componentized into the following:

- IED
- Battery

32.3.1 *IED*

The useful life of the IED in IED based SCADA is in the range of 10 to 15 years; the typical life is 15 years.

32.3.2 *Battery*

The useful life of the battery in IED based SCADA is in the range of 5 to 20 years; the typical life is 10 years.

32.4 Time Based Maintenance Intervals

IED based SCADA is not subject to planned maintenance.

32.5 Impact of Utilization Factors

This asset is impacted by Operating Practices. It is specifically the battery component that is affected by operating practices. If this device is running within an electrically stable system there will be less stress imposed on it.

33 Fault Indicators

Fault indicators are used for loaded underground distribution circuits where secondary voltage is available - pad mounted transformers, switchgear and underground vault applications. A sensor monitors the line current. When the trip rating is exceeded, the indicator trips to the fault position. To reset the display the fault indicator uses a secondary voltage source, such as the low-voltage terminals of distribution transformers.

33.1 Degradation Mechanism

Fault indicators have durable Lexan housings, and utilize coated nickel iron sensor laminations encapsulated in a polyurethane potting compound for environmental protection. Overhead fault indicators use batteries, hence their useful life is based primarily on the end of life of the battery itself. The useful life of overhead fault indicators is significantly less than underground fault indicators due to this battery component.

33.2 System Hierarchy

Fault Indicators asset category belongs to the Monitoring and Control Systems assets grouping.

33.3 Useful Life and Typical Life

The overall useful life range of the fault indicator itself is dependent on the type:

- Overhead
- Underground

33.3.1 *Overhead*

The useful life of the overhead fault indicator is based on the useful life of its battery which is in the range of 5 to 20years; the typical life is 10 years.

33.3.2 *Underground*

The useful life of the underground fault indicator is in the range of 10 to 30 years; the typical life is 20 years.

33.4 Time Based Maintenance Intervals

Fault Indicators are not subject to planned maintenance.

33.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

34 Metering

The metering is how electricity providers measure billable services by measuring various aspects of power usage. When used in electricity retailing, the utilities record the values measured by these meters to generate an invoice for the electricity. This report focuses on those meters used for residential meters, industrial/commercial meters and wholesale meters. This asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT).

34.1 Degradation Mechanism

The major degradation mechanism of traditional meters is listed as follows:

- Electronic component aging due to long-term power quality impact, for solid-state meters
- Meter creep due to high temperature for induction type meters. This occurs when the meter disc rotates continuously with potential applied and the load terminals open circuited
- Magnetization alteration due to overload or short-circuited conditions
- Mechanical damage due to vibration of meter mounting
- Other adverse operating environment that might expedite the aging of components, such as humidity or dirt

34.2 System Hierarchy

Metering asset category belongs to the Monitoring and Control Systems assets grouping.

34.3 Useful Life and Typical Life

There are two components of the meter which have their own useful and typical life:

- Meter (Residential, Industrial/Commercial, Wholesale)
- Transformer (Current, Potential)

34.3.1 *Meter*

The useful life range of residential type meter is 20 to 45 years; typical life is 30 years.

The useful life range of industrial/commercial type meter is 20 to 60 years; typical life is 30 years.

The useful life range of wholesale type meter is 20 to 60 years; typical life is 30 years.

34.3.2 *Transformer (Current, Potential)*

The useful life range of the CT component is 30 to 50 years; typical life is 45 years.

The useful life range of the PT component is 30 to 50 years; typical life is 45 years.

34.4 Time Based Maintenance Intervals

Meters are not subject to planned maintenance

34.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

35 Smart Metering

A smart meter is an advanced meter is an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via some network back to the local utility for monitoring and billing purposes.

35.1 Degradation Mechanism

The major degradation mechanism of smart metering system is listed as follows:

- Wiring insulation deterioration due to corrosion, moisture or overheating
- Poor electrical connections due to corrosion, vibration or other physical problems
- Cabinetry or rack damage or wear
- Faulty electronic components

The rate and severity of degradation in the equipment depend on its operational duties and environmental factors. Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in microwave equipment of smart metering system.

Environmental conditions in relay and switch-rooms can affect microwave equipment's condition and reliability. Humidity, temperature, dust and pollution can cause component degradation. When plant temperatures fall below the dew point condensation can occur. When water enters equipment rooms through roof or other leaks, it can affect performance and aggravate corrosion.

Typically, terminations and connectors experience mechanical degradation. In damp locations it is common for verdigris, which is the green coating or patina formed when copper, brass or bronze is weathered and exposed to air or seawater over a period of time, to form. Typical problems for these components include:

- Failed crimped terminations due to movement
- Cracked terminal blocks
- Stripped threads
- Mechanical damage from over tightening

Typical degradation processes for the cabinets or racks include:

- Corrosion
- Loss of mechanical strength through use (e.g. swing front panels)

Microwave electronics in smart metering system range from capacitors and resistors to solid-state printed circuit boards. All electronic components have finite lifetimes. Modern highly integrated electronic equipment consists of application specific integrated circuits, surface mounted components, and multi-layer boards.

35.2 System Hierarchy

Smart Metering asset category belongs to the Monitoring and Control Systems assets grouping.

35.3 Useful Life and Typical Life

There are several components of the smart meter which have their own useful and typical life:

- Smart Meter
- Repeater
- Data Concentrator
- Powerline Repeaters

35.3.1 *Smart Meter*

The useful life range of the smart meter is 15 to 20 years; typical life is 15 years.

35.3.2 *Repeater*

The useful life range of the repeater is 5 to 15 years; typical life is 10 years.

35.3.3 *Data Concentrator*

The useful life range of the data concentrator is 10 to 20 years; typical life is 20 years.

35.3.4 *Powerline Repeaters*

The useful life range of the powerline repeater is 5 to 15 years; typical life is 10 years.

35.4 Time Based Maintenance Intervals

Smart Meters are not subject to planned maintenance

35.5 Impact of Utilization Factors

This asset is impacted by Environmental Conditions.

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Appendix C

Indefeasible Right of Use - Estimate of Value Report

TR CONSULTING INC.

Retrospective Valuation of Certain Fibre Optic Strands Acquired by a Indefeasible Right of Use

Oakville Hydro Electricity Distribution Inc.

Acquired From

Blink Communications Inc.

As At: January 4, 2010

Machinery and Equipment Appraisers and Consultants

TR CONSULTING INC.
MACHINERY AND EQUIPMENT VALUATIONS
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February 28, 2011

Oakville Hydro Electricity Distribution Inc.
P.O. Box 1900
861 Redwood Square
Oakville, ON, L6J 5E3

Attention: Ms. Lesley Gallinger, MBA, CMA, CPA, CDir.
Vice President, Corporate and Regulatory Affairs
and Chief Financial Officer

Dear Sirs:

Subject: **Valuation of Certain Fibre Cable Strands Acquired by an Indefeasible Right of Use from Blink Communications Inc.**

Pursuant to our letter of understanding dated November 29, 2010, we have been engaged to provide Oakville Hydro Electricity Distribution Inc. ("Oakville Hydro" or "the company") with an independent and objective retrospective estimate of the Fair Market Value of certain fibre optic cable strands (the "Asset") acquired by an Indefeasible Right of Use ("IRU") from Blink Communications Inc. ("Blink").

Our report has been completed in accordance with the Uniform Standards of Professional Appraisal Practices ("USPAP") and in our opinion complies with the requirements of a "Summary Appraisal Report" (www.appraisalfoundation.org).

Background

We understand that on or about January 4, 2010 Oakville Hydro obtained an IRU from Blink as it pertains to a pair of fibre optic cable strands, having a paired strand length of approximately 61,600 meters.

Oakville Hydro Electricity Distribution Inc.
February 28, 2011

Purpose and Date

The purpose of our valuation is to support a rate based filing that Oakville Hydro will present to the Ontario Energy Board ("OEB").

Our valuation is as of January 4, 2010 (the "Valuation Date").

Restrictions

This report is not intended for general circulation or publication, nor is it to be reproduced or used for any purpose other than that outlined above without our written permission in each specific instance. We do not assume any responsibility or liability for losses incurred by any party as a result of circulation, publication, reproduction or use of this report contrary to the provisions of this paragraph.

We reserve the right to review all calculations included or referred to in this report and, if we consider it necessary, to revise our estimate of value in the light of any information existing at the effective date which becomes known to us after the date of this report.

Supporting data upon which this estimate is based are contained in the accompanying report, subject to the Assumptions and Limiting Conditions contained within the body of the report.

This estimate of value has been derived using generally accepted appraisal procedures and on a level of due-diligence appropriate for the purpose. In order for us to provide an opinion of value, a more comprehensive scope of investigation and analysis would be required.

This appraisal report should read its entirety. Reports of this nature do not lend themselves to summary description or partial analysis. The preparation of an appraisal is a complex task and without understanding all the points and factors considered by us, a misleading or inappropriate view of the entire process may result.

We were engaged only to complete an estimate of the Fair Market Value of the Asset as at the Valuation Date. We were not engaged to comment on the appropriateness of Oakville Hydro's accounting treatment relating to the Asset, nor were we engaged to comment on other accounting issues and legal or engineering matters relating to the Asset.

TR CONSULTING INC.

Oakville Hydro Electricity Distribution Inc.
February 28, 2011

Estimate of Value

Based upon the scope of our review, and our research, analysis and experience, our estimate of the Fair Market Value of the Asset understood to have been acquired by Oakville Hydro, as at January 4, 2010, is as follows (rounded):

Oakville Hydro Electricity Distribution Inc.
61,588 Meters of a Paired Fibre Optic Cable IRU
Fair Market Value
As At: January 4, 2010

Eight Hundred and Ninety-four Thousand, Eight Hundred
Canadian Dollars
(C$894,800)

The following twenty-two (22)-page report, including assumptions and limiting conditions and five (5) attached schedules and/or appendices, is an integral part of this valuation and summarizes our findings and the methodology leading to our estimate of Fair Value.

Yours very truly,
TR CONSULTING INC.

TR Consulting Inc

Ted Rudyk, ASA, MRICS

Table of Contents

Assumptions and Limiting Conditions

The investigation and the valuation estimate expressed in this appraisal are subject to the following critical assumptions and limiting conditions including any others that are expressed or implied in this report. Acceptance and/or use of this report constitutes acceptance of all assumptions and limiting conditions in this report.

This report is not intended for general circulation nor is it to be reproduced or used for any purpose other than as outlined herein without our prior written permission in each specific instance. We do not assume any responsibility or liability for losses occasioned to the company, its directors or shareholders or to other parties as a result of the circulation, publication, reproduction or use of this report contrary to the provisions of this paragraph.

We reserve the right (but will be under no obligation) to review all calculations included or referred to herein and, if we consider it necessary, to revise our report in light of any information existing at the valuation date which become known to us after the date of this report.

The Asset interest (or rights) being valued is that of ownership in fee simple (ownership without limitation to any particular class of heirs or restrictions, but subject to the limitations of the rights of taxation, police power, expropriation and escheat), and accordingly, our investigation did not include any title searches, opinions of title, personal property security liens searches, encroachments or encumbrances reviews, liability searches or any similar types of reviews or searches. We do not take any responsibility for these matters or any other similar matters. We have assumed that title to the Asset outlined herein is free and clear and fully marketable.

We did not inspect the Asset or any portion of the fibre optic cable that takes up this IRU. Additionally, we did not complete a review of the broadband capacity of the Asset, detailed technological advancement reviews, as well as any other specialized studies were made in conjunction with this report and are considered outside the scope of this investigation. Accordingly, no responsibility is assumed concerning these matters, or other technical or engineering techniques, which would be required to discover any inherent or hidden condition in the equipment and full compliance with applicable regulations and laws is assumed unless stated otherwise.

Based on discussions with Blink management, we have assumed that the Asset is operating according to design parameters. Our appraisal has been based on this assumption. Should we subsequently find out that these assumptions are incorrect, we would have to reassess our value of the Asset.

This valuation report does not give any consideration to the possible effect on the values reported herein, as a result of inflation, currency differences, interest rate differences, changing economy, changing technology etc., expected or projected. Values are as of the appraisal date.

The terms of this engagement do not require us to give outside consultation, testimony or appear before any court of law. In the event that outside consultation, testimony or court appearance becomes necessary, we will be pleased to further assist you as required.

The fee for the valuation report is not contingent upon the conclusions expressed herein.

Information received from Blink personnel has been assumed to be accurate and reliable. We have not completed a review, analyzed or audited this information and assume no responsibility to the contrary.

The valuation does not affix or set the price for the Asset but offers only a supportable estimate as to the present worth of anticipated benefits subject to investment risk, measured mainly by the market data available at the valuation date. Therefore, we assume no liability for changes in market conditions that may adversely affect the stated values.

We are not aware, nor has Oakville Hydro or Blink management notified us, of any facts or material information that would reasonably be expected to affect the conclusions expressed herein.

This report is not valid unless it bears the original signature of the appraiser.

This appraisal of the equipment of Blink complies with our understanding of the requirements of the Uniform Standard of Professional Appraisal Practice ("USPAP") and has been prepared using generally accepted valuation methodology and techniques as promulgated by the American Society of Appraisers (www.appraisers.org).

All files, work papers or other documents developed during the course of this assignment shall be our property. We will retain these documents for five (5) years.

Should any of the above assumptions and limiting conditions not be accurate or should any of the information provided to us not be factual or correct, our value conclusion could be significantly different.

1. Currency of Valuation

Values stated in this report are expressed in Canadian Dollars (C$). Conversion or translation into other currencies should be taken at the exchange rates prevailing as at the valuation date.

2. Purpose and Date of the Valuation

The purpose of our valuation is to support a rate based filing that Oakville Hydro will present to the OEB.

The Valuation Date is as of January 4, 2010.

3. Nature of the Asset's Utilization

It is our understanding that the Asset is being utilized to provide Oakville Hydro with communicate (via Scada) with its sub-stations, as well as, to remotely monitor the stations for fire, access, etc.

4. Inclusions and Exclusions

This valuation only includes the following:

Fibre Optic Cable –	61,588 paired stranded meters (including stored slack) of Single Mode Fibre ("SMF") fibre optic cable

Our valuation has excluded all other forms of tangible (and intangible) assets owned by Oakville Hydro or Blink.

5. Highest and Best Use

In the appraisal of machinery and equipment, which in appraisal practice is part of the all encompassing "Personal Property" category of fixed assets (while land and building is considered "Real Property"), the highest and best use of the equipment must be addressed. According to USPAP, which sets out standards of professional appraisal practice, highest and best use must be addressed. The USPAP definition of highest and best use is as follows: *"The reasonably probable and legal use of personal property that is physically possible, appropriately supported, and financially feasible, and results in the highest value in the appropriate marketplace".*

The above definition can be also considered as follows:

- The use contemplated must be legally permissible, or the contemplated highest and best use must have a reasonable probability of being achieved.

- The personal property must be physically suitable or capable of being physically adapted to sustain the use being contemplated.

- The use contemplated must be economically feasible and there must be a demand in the market place for the contemplated use, such that the personal property reflects the most economically advantageous use of the personal property.

If any of these criteria cannot be met then the highest and best use contemplated becomes invalid. Based upon the above, and with due consideration to the special nature and/or purpose built nature of the Asset, we have concluded that the current use represents the highest and best use.

Based upon the above we have concluded that there is no other economically viable alternate use from the Asset and, accordingly, the current use represents the highest and best use.

6. Scope of Work

Our scope of work was limited to the following:

1. Discussions were held with Blink management (Terry Crawford, Director of Facilities and Infrastructure) to determine such things as, but not limited to: age, operational status, loaded replacement cost new, type of fibre optic cable utilized, percentage that was aerial and buried and in duct and other miscellaneous topics.

2. Application of generally acceptable appraisal procedures specific to the valuation of machinery & equipment.

The interest (or rights) being valued is that of ownership in fee simple (ownership without limitation to any particular class of heirs or restrictions, but subject to the limitations of the rights of taxation, police power, expropriation and escheat), and accordingly, our investigation did not include any title searches, opinions of title, personal property security liens searches, encroachments or encumbrances reviews, liability searches or any similar types of reviews or searches.

This estimate of value has been prepared in conformity with the Principles of Appraisal Practice and Code of Ethics of the American Society of Appraisers and the Uniform Standards of Professional Appraisal Practices.

7. Fair Market Value

According to the American Society of Appraisers – Machinery and Technical Specialties, **Fair Market Value ("FMV")** is defined as follows: an opinion expressed in terms of money, at which the property would change hands between a willing buyer and a willing seller, neither being under any compulsion to buy or to sell and both having reasonable knowledge of relevant facts, as of a specific date.

FMV as defined above is a concept of value and may or may not equal the purchase/sale price in a market transaction. Each purchaser would likely pay a different price for the Assets for numerous reasons, such as but not limited to: perceived economies of scale, cost savings, reduced or eliminated competition, desirability of the operations or other synergies which could be enjoyed by the purchaser. Only through negotiations can these factors and the final price be determined.

The term FMV is not intended to represent an amount that may be realized from assembled or piecemeal disposition of the Asset in the open market place through liquidation or from some other use of the Asset that would result in a significantly lower value, net any costs of disposition.

7.1 Methods of Determining Fair Market Value

The three generally accepted methods of determining FMV are the cost (also known as the depreciated replacement cost approach), market and income approaches to value.

The cost approach considers the cost to reproduce or replace and install the assets being appraised. From this amount, a deduction is made for depreciation or obsolescence present, whether arising from physical, functional or economic causes. Generally speaking, the cost approach is used when valuing assets such as, but not limited to, process facilities, special purpose or purpose built installations or networks, specialized equipment or equipment with no known or readily identifiable used marketplace.

The market approach considers prices recently paid for similar or identical assets, with adjustments made to the indicated market prices, to reflect the condition and utility of the appraised Asset relative to the market comparable assets. When valuing assets using the market approach, estimates should be based upon sales of identical assets, which have been exchanged in the marketplace. Unfortunately, it is rare to find exact market sales of identical assets. In practice, the market investigation will probably reveal sales of similar assets, and it is the analysis of similarity upon which the estimate of value is based. The market approach is used when valuing assets with a readily identifiable used marketplace such as over-the-road vehicles, metalworking equipment, textile machinery, plastic injection moulding equipment, woodworking equipment and other similar types of assets that have an identifiable secondary (used) marketplace.

In the income approach, an estimate is made of the prospective economic benefit of ownership. These amounts are capitalized at appropriate rates of return into an indication of value.

The approaches selected as the most suitable must be by the facts and circumstances surrounding the Asset. The applicability of any approach in a given appraisal depends on the purpose of the appraisal, the type of assets involved, the nature of the market and the availability of the required data. Traditionally, the approaches relied upon are the cost and market approaches to value. The income approach is not normally used due to the virtual impossibility of measuring the financial contribution that each asset or groups of assets contribute towards the whole.

Regardless of the approach to value used, the underlying principle involved in the valuation of the Asset is the Principle of Substitution. This principle is established on the basis that an informed purchaser will pay no more for the Asset than what it would cost them to produce or acquire an equally desirable substitute asset of equal utility and function.

Based upon the above and with due consideration to the purpose built nature of the Asset, our analysis utilized only the cost approach to value the fibre optic cable acquired by Oakville Hydro. In this instance, it is our opinion that the income approach was not applicable and therefore not considered by us.

7.2 Cost Approach

The cost approach to value is a valuation technique that uses the concept of replacement as a value indicator. This approach relies on the principle of substitution and recognizes that a prudent investor would pay no more for the equipment than the cost to reproduce or replace the equipment new with an identical or similar unit of equal utility.

The replacement cost new (“RCN”) establishes the highest amount a prudent investor would pay for the equipment. Since the equipment we are valuing will generally provide less utility than a new asset, adjustments for losses in value due to causes of physical deterioration and functional obsolescence are applied.

As outlined within the American Society of Appraiser "Appraising Machinery and Equipment" (2000 Edition), the cost approach is defined as: that approach which measures value by determining the current cost of an asset and deducting for the various elements of depreciation, physical deterioration and functional and economic obsolescence.

The following are commonly used terms when utilizing the depreciated replacement cost method for the valuation of equipment:

Replacement Cost New – is the cost of substituting an asset with another asset having equivalent utility using current rates for materials and labour.

Physical Deterioration – is a reduction in utility resulting from an impairment of physical condition. This is brought about by such factors as age, condition, wear and tear, structural defects, exposure to damaging elements and other physical factors that reduce the life and serviceability of the equipment.

Functional Obsolescence – is the impairment of functional capacity or efficiency caused by factors inherent in an asset. This is brought about by such factors as excess or over capacity, under-utilization, inadequacy, excess operating costs, changes in technology, availability of spare parts, etc. that effect the asset or its relation to other items comprising the larger property. It is also the inability of an asset to perform adequately the function for which it is currently employed.

Economic Obsolescence – is the loss in value resulting from factors external to the equipment. These could include, but are not limited to, the following: such as increased raw material costs, increased labour costs, legislative enactments, and other external factors which impact on the value of the equipment. Economic obsolescence is difficult to quantify on an individual asset basis with respect to each asset in a facility. Accordingly, the quantification of economic obsolescence is best made on a collective, or full facility, basis.

The following briefly describes the methodology for determining the FMV utilizing the cost approach:

1. Estimate the RCN. Utilizing information received from Blink regarding the Asset (i.e. – the percentage of the Asset that is above ground and below ground, cost per meter for above ground and below ground construction, the approximate percentage of meters built per year from 1999, etc.), the RCN was estimated by us. In determining the RCN, we understand that approximately 85% of the Asset is considered as backbone fibre, while the balance is considered as drop fibre.

We also understand that backbone fibre is 48 sheath fibre optic cable, while drop fibre is in 6 sheath fibre optic cable. For fully burdened per meter cost to install overhead and underground backbone fibre, we utilized $13,90 and $77.08, while for the fully burdened per meter cost to install overhead and underground drop fibre, we utilized $14.09 and $77.28.

In arriving at the abovementioned per meter costs, adjustments were made only to the material costs, as the Asset that is within the backbone represents two strands of an entire 48 strand / sheath cable, while for the drop fibre the Asset represents two strands with a 6 strand / sheath cable. Accordingly, for the material cost of the backbone fibre, we utilized a 2/48 per meter cost ($0.07 per meter) rather than the full material cost of 48 strand fibre optic cable. Similarly, for the material cost of the drop fibre, we utilized a 2/6 per meter cost ($0.24 per meter) rather than the full material cost of a 6 strand fibre optic cable. No adjustments were made to the cost of installation, duct, incidentals, etc., as these types of costs remain constant regardless of the fibre optic cable size being placed.

Schedule 3 summarizes the information utilized by us to estimate the RCN.

2. Estimate the physical depreciation. Once the RCN is estimated, it is depreciated on an "age/life" method. The normal useful life ("NUL") is established and an estimate of the overall average remaining useful life ("RUL") is made. The RCN is multiplied by the RUL and then divided by the NUL. Based upon our previous experience in valuing fibre optic cable networks, the table below indicates the NUL utilized:

	NUL (In Years)
Fibre Optic Cable	20

To determine the quantity (length) of the Asset that was installed on a year by year basis, we held discussions with Blink management, as well as reviewed database materials we have regarding the overall Blink fibre optic network. The table below indicates the percentage amount of the Asset that was installed on a year by year basis:

Mid-year	
30-Jun-99	15.0%
30-Jun-00	20.0%
30-Jun-01	20.0%
30-Jun-02	12.5%
30-Jun-03	10.0%
30-Jun-04	5.0%

Mid-year	
30-Jun-05	5.0%
30-Jun-06	5.0%
30-Jun-07	3.5%
30-Jun-08	2.0%
30-Jun-09	2.0%

3. Estimate the functional obsolescence. Functional obsolescence is the impairment of functional capacity or efficiency caused by factors inherent in an asset. This is brought about by such factors as overcapacity, under-utilization, excess operating costs, changes in technology, etc. that effect the item of equipment or its relation to other items of equipment comprising the total machinery and equipment.

   Based on the understanding that the Asset's fibre optic cable is single mode fibre ("SMF") and is able to provide Dense Wavelength Division Multiplexing ("DWDM") transportation, it is our opinion that functional obsolescence is not applicable.

The table below provides outlines the functional obsolescence utilized:

	Percentage
Fibre Optic Cable	0%

Note – Functional Obsolescence factors based on our previous experience in valuing fibre optic cable service providers

4. Estimate the economic obsolescence. Economic obsolescence is the loss in value caused by factors external to the equipment. This form of obsolescence is a function of outside influences that affect an entire business (i.e. all tangible and intangible assets) rather than individual items or groups of equipment and is best measured by the income approach. An income approach is outside the scope of our expertise and, accordingly, was not considered by us.

The table below provides an illustration of the cost new approach:

Develop:	Replacement Cost New
Deduct For:	Physical Depreciation
	Functional Obsolescence
	Economic Obsolescence
Result:	FMV

8. Valuation Analysis

In addition to the above, we have considered the following in our analysis and subsequent valuation:

- The Asset has a significant remaining useful life.
- There is responsible ownership and management.
- Continuation of existing use by present or similar users is practical.
- The diversion of the Asset for some alternate application or use would not be legally permitted or economically viable.

9. Conclusion of Value

Based upon the scope of our review, and our research, analysis and experience, our estimate of the Fair Market Value of the Asset understood to have been acquired by Oakville Hydro from Blink Communications, as at January 4, 2010, is as follows (rounded):

Oakville Hydro Electricity Distribution Inc.
61,588 Meters of a Paired Fibre Optic Cable IRU
Fair Market Value
As At: January 4, 2010

	Canadian $
Backbone Fibre	759,600
Drop Fibre	135,200
Grand Total	894,800

CERTIFICATE OF APPRAISER SCHEDULE 1

I certify that:

- To the best of my knowledge and belief the statements of facts, upon which the analyses, opinions and conclusions expressed in this report are based, are true and accurate.
- That no personal inspection of the Asset was made as described within this report.
- That this report sets forth all the limiting conditions affecting the analysis, opinions and conclusions expressed herein.
- This report has been made in conformity with, and is subject to the Code of Ethics of the American Society of Appraisers and the Uniform Standards of Professional Appraisal Practices.
- I have no present or contemplated future interest in the appraised property nor any personal interest or bias with respect to the subject matter or to the principles and property appraised.
- I comply with the competency provisions for the appraisal of machinery and equipment as a consequence of my experience valuing similar types of assets and the American Society of Appraisers' mandatory recertification program for all of its senior members. As a senior member (designated by the initials ASA) I am in compliance with the requirements of that program.
- That no one other than the undersigned prepared the analyses, opinions and conclusions concerning the machinery and equipment value set forth in the appraisal report.
- That neither the employment nor the compensation for making this report is in any way contingent upon the value reported therein.

March 21, 2011	
Date	Ted Rudyk, ASA, MRICS

SCHEDULE 2 SUMMARIZED FMV VALUATION TABLE

Schedule 2 – Summarized FMV Valuation Tables
Canadian Dollars (C$)

Table 1

Backbone Fibre Optic Cable	
52,350 strand meters of backbone fibre	
Replacement Cost New	1,223,780
Less depreciation resulting from age/life (physical):	-464,140
Sub-total:	759,640
Less depreciation resulting from functional obsolescence	0
Total, estimated Fair Market Value of the Backbone Fibre IRU:	759,640
Rounded To:	**759,600**

Table 2

Drop Fibre Optic Cable	
9,238 strand meters of drop fibre	
Replacement Cost New	217,730
Less depreciation resulting from age/life (physical):	-82,580
Sub-total:	135,150
Less depreciation resulting from functional obsolescence	0
Total, estimated Fair Market Value of the Drop Fibre IRU:	135,150
Rounded To:	**135,200**

SCHEDULE 3 INFORMATION UTILIZED FOR RCN

Schedule 3 – Information Utilized
For RCN

Overhead Installation Costs (2010 pricing)
per metre

	O / head Install Cost	Cable Material	Sub-Totals	Incidental @ 10%	Grand Total ($ / M)
2/6 count	$12.57	$0.24	$12.81	$1.28	$14.09
6 count	$12.57	$0.72	$13.29	$1.33	$14.62
12 count	$12.57	$0.79	$13.36	$1.34	$14.70
24 count	$12.57	$1.03	$13.60	$1.36	$14.96
2/48 count	$12.57	$0.07	$12.64	$1.26	$13.90
48 count	$12.57	$1.58	$14.15	$1.42	$15.57
96 count	$12.57	$3.92	$16.49	$1.65	$18.14
144 count	$12.57	$5.71	$18.28	$1.83	$20.11

Underground Cable Installation
per metre

	Cable Install	Duct Install	Cable Material	Duct Material	Sub-Totals	Incidental @ 10%	Grand Total ($ / M)
2/6 count	$19.25	$45.00	$0.24	$5.76	$70.25	$7.03	$77.28
6 count	$19.25	$45.00	$0.72	$5.76	$70.73	$7.07	$77.80
12 count	$19.25	$45.00	$0.79	$5.76	$70.80	$7.08	$77.88
24 count	$19.25	$45.00	$1.03	$5.76	$71.04	$7.10	$78.14
2/48 count	$19.25	$45.00	$0.07	$5.76	$70.08	$7.01	$77.08
48 count	$19.25	$45.00	$1.58	$5.76	$71.59	$7.16	$78.75
96 count	$19.25	$45.00	$3.92	$5.76	$73.93	$7.39	$81.32
144 count	$19.25	$45.00	$5.71	$5.76	$75.72	$7.57	$83.29

APPENDIX A QUALIFICATIONS OF TED RUDYK

Ted Rudyk, ASA
Machinery and Equipment Appraisals

BACKGROUND

Ted Rudyk has been providing machinery and equipment appraisal advice for over 30 years. His experience encompasses a wide range of machinery and equipment involving single pieces of equipment, manufacturing plants, process facilities, healthcare facilities, telecommunications and numerous other types machinery and equipment and industries. His services have been required for going concern valuations, liquidation opinions, tax matters, insurance placement, fixed asset property control systems and other accounting or corporate requirements.

PROFESSIONAL EXPERIENCE

Mr. Rudyk has experience in a wide range of issues and problems including the following:

- Valuation of equipment within a going concern enterprise
- Financing involving asset based debt offerings
- Purchase price allocation, export, estate planning and other tax related issues
- Shareholder dispute, matrimonial matters and other litigious issues
- Corporate organizations issues
- Fixed asset reconciliation and property control requirements
- Determining value in joint venture agreement

SELECTION OF CANADIAN VALUATION ASSIGNMENTS

- For corporate planning purposes, valued a USA based long haul and metro fibre optic network having total route kilometre length of approximately 4,400 kilometres
- For purchase price requirements, valued the machinery and equipment and fibre optic back-bone network of a Ontario based competitive local exchange carrier ("CLEC")
- For purchase price requirement, valued the machinery and equipment at a cellular / wireless telephone provider having approximately 1,200,000 customers
- For tax reasons valued the wireless network of a cellular telephone provider having approximately 4,000,000 customers
- For tax reasons, valued the equipment of an incumbent telephone exchange carrier ("ILEC") having over 25 million service lines
- For tax reasons, valued certain wireline and wireless machinery and equipment of a western Canada based ILEC

SELECTED INTERNATIONAL VALUATIONS ASSIGNMENTS

- For privatization reasons, valued the equipment at 5 thermal fired power plants, 30 run-of-river hydro dams and a high voltage grid system in the Slovak Republic
- For US tax reasons, appraised the machinery and equipment at a specialty chemical company in Buxton, England and Lucerne, Switzerland
- For privatization reasons, appraised the machinery and equipment at two bauxite mines in Guyana, South America
- For privatization purposes, valued the equipment at a chemical processing plant in Lisbon Portugal
- For USA based tax reasons, valued the equipment at a bottling plant in Naples Italy
- To determine shareholder contribution towards a new start-up company, appraised an integrated two piece aluminum can forming line – Dubai United Arab Emirates
- To assist to certain potential privatization requirements, value the machinery and equipment at Bahamas Telecommunications Corporation, the national telephone company of The Commonwealth of The Bahamas

APPRAISAL INDUSTRY EXPERIENCE

Oct. 08 to present:	**TR Consulting Inc.** Providing independent machinery and equipment appraisal services for various clients.
Jan. 08 to Sept. 08:	**Deloitte & Touche LLP** Managing Director; Machinery & Equipment Appraisal Practice
Apr. 99 to Jan. 2008:	**TR CONSULTING INC.** Providing independent machinery and equipment appraisal services for various clients.
Feb. 98 to Mar. 99:	**PricewaterhouseCoopers LLP (or one of its predecessors firms Coopers & Lybrand)** Manager; Machinery & Equipment Appraisal Practice
Jan. 93 to Jan. 98:	**TR CONSULTING INC.** Providing independent machinery and equipment appraisal services for various clients.
Sept. 92 to Jan. 93:	**American Appraisal Canada, Inc.** Senior Appraiser; Machinery and Equipment Group
Jan. 89 to Sept. 92:	**KPMG Peat Marwick Thorne (or one of its predecessors Thorne Ernst and Whinney)** Senior Manager; Machinery & Equipment Appraisal Practice

June 79 to Dec. 88: **General Appraisal of Canada Limited**
Junior Machinery and Equipment Appraiser culminating to Machinery and Equipment Group Manager

PROFESSIONAL AFFILIATIONS

Accredited Senior Appraiser (ASA), Machinery & Equipment - American Society of Appraisers, Washington DC, USA (www.appraiser.org)

Member (MRICS) – The Royal Institution of Chartered Surveyors, London, England (www.rics.org)

Associate Member – Appraisal Institute of Canada Ottawa, Canada (www.aicanada.ca)

MISCELLANEOUS

Mr. Rudyk has completed assignments throughout Canada and the United States, Barbados, The Bahamas, China, Belgium, Denmark, England, Germany, Guyana, Holland, Italy, Luxembourg, Mozambique, Portugal, Slovak Republic, Switzerland, United Arab Emirates and Venezuela.

Accepted as an expert witness in the appraisal of machinery and equipment by the Ontario Court of Justice, General Courts Division

Appendix B American Society of Appraisers and The Royal Institution of Chartered Surveyors

The American Society of Appraisers is an organization of appraisal professionals and others interested in the appraisal profession. International in structure, ASA is the oldest and only major appraisal organization representing all of the disciplines of appraisal specialists. The society originated in 1936 and incorporated in 1952. ASA is headquartered in the metropolitan Washington, D.C., area.

The society is dedicated to the benefit of the appraisal profession. It is one of eight major appraisal societies that, in 1987, founded The Appraisal Foundation, an international nonprofit organization created to establish uniform criteria for professional appraisers. Since 1989 The Appraisal Foundation has been recognized by the U.S. Congress as the source for the development and promulgation of appraisal standards and qualifications.

Each accredited member of the American Society of Appraisers has earned a professional designation in one or more specialized areas of appraisal. To become accredited, ASA Members must pass intensive courses and written examinations, submit representative appraisal reports, provide an appraisal experience log and provide evidence of a college degree or its equivalent.

Every accredited appraiser must start his or her ASA membership as an Applicant and has ten months to pass ASA's Ethics Examination and a course and examination on the Uniform Standards of Professional Appraisal Practice (USPAP). USPAP is published each year by The Appraisal Foundation.

To qualify for the Accredited Member designation (AM), an individual must have at least two years of full-time equivalent appraisal experience and to qualify for the Accredited Senior Appraiser designation (ASA), an individual must have a minimum of 5 years of full-time equivalent appraisal experience.

ASA has a mandatory re-accreditation process whereby designated members must regularly submit evidence of professional growth through participation in professional activities and continuing education. This ensures that ASA appraisers keep their knowledge up-to-date.

The Royal Institution of Chartered Surveyors ("RICS") is the pre-eminent organisation of its kind in the world. As such, it represents everything that is good in the property profession.

Our members offer the very best advice on a surprisingly diverse range of land, property, construction and related environmental issues.

As part of our role, we help to set, maintain and regulate standards. We also provide impartial advice to governments and policy-makers.

RICS operates out of 146 countries, supported by an extensive network of regional offices located in every continent around the world.

The **Machinery and Business Assets Faculty** is the home within RICS for those members who have a range of skills and expertise that allows them to advise on the valuation and sale of both tangible and intangible assets throughout the world.`

Exhibit	Tab	Schedule	Appendix	Contents
3 – Operating Revenue				
	1	1		Load and Revenue Forecasts
		2		Multivariate Regression Model
		3		CDM Adjustment for the Load Forecast for Distributors
	2	1		Accuracy of the Load Forecast and Variance Analysis
	3	1		Other Revenue
				Appendix
			A	Milton Hydro Load

Load and Revenue Forecasts

This Exhibit provides the details of Oakville Hydro's operating revenue for 2010 Board Approved, 2010 Actual, 2011 Actual, 2012 Actual, the 2013 Bridge Year and the 2014 Test Year. This Exhibit also provides a detailed variance analysis by rate classification of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

Oakville Hydro is proposing a total Base Revenue Requirement of $36,880,386 for the 2014 Test Year. This amount reflects a Service Revenue Requirement of $38,916,139 and revenue offsets of $2,035,753 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3-1 and provides a comparison of total revenues from the 2010 Board approved year to the 2014 Test Year.

Table 3-1: Summary of Operating Revenue

Operating Revenues	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Distribution Throughput Revenue						
Residential	$17,174,410	$17,594,797	18,241,865	$18,998,962	$20,553,737	$21,508,431
General Service < 50 kW	4,451,203	4,083,476	4,433,621	4,505,513	4,837,423	$3,997,189
Unmetered	136,242	146,426	132,889	136,384	139,533	$116,925
General Service > 50 kW	7,261,045	6,219,844	7,016,243	7,336,766	7,560,555	$8,501,101
General Service > 1,000 kW	1,357,198	1,266,675	1,340,917	1,308,203	1,287,656	$1,524,423
Embedded Distributor	-	-	-	-	58,833	$176,026
Sentinel Lighting	17,809	6,915	14,921	19,671	22,826	$20,397
Street Lighting	738,744	488,842	904,731	1,204,700	1,307,271	$1,035,894
Total	**$31,136,649**	**$29,806,975**	**$32,085,187**	**$33,510,199**	**$35,767,833**	**$36,880,386**
Other Distribution Revenue						
Specific Service Charges	342,325	300,454	278,387	314,040	272,600	282,200
Late Payment Charges	256,834	288,100	314,134	335,244	321,726	325,000
OtherDistribution Revenues	827,874	883,648	834,675	847,766	878,299	863,733
Other Income or Deductions	636,130	1,884,270	1,098,694	944,892	583,097	564,820
Total	**$2,063,163**	**$3,356,472**	**$2,525,890**	**$2,441,942**	**$2,055,722**	**$2,035,753**
Total Operating Revenues	**$33,199,812**	**$33,163,447**	**$34,611,077**	**$35,952,141**	**$37,823,554**	**$38,916,139**

Load Forecast

Overview

Oakville Hydro has used a multivariate regression model to forecast the weather normalized load forecast for the 2014 Test Year. The "total system weather normalized purchased energy forecast" is developed based on a multifactor regression model that incorporates historical load, weather, days in the month and customer data.

As illustrated in Table 3-2, Oakville Hydro's forecasted energy consumption for the 2014 test year is 65,687,116 kWh or 4.41% higher than its 2010 Board Approved kWh. Oakville Hydro's forecasted number of new customers for the 2014 Test Year, excluding unmetered customers, is 853 or 1.32% higher than 2010 Board Approved customer numbers which illustrates very low growth over a four-year period.

Table 3-2: Load and Customer Growth – 2014 Test Year vs. 2010 Board Approved

Year	2010 Board Approved	2014 Test Year	kWh Change	Percentage Change
Billed kWh	1,488,242,062	1,553,929,178	65,687,116	4.41%
Number of Customers	64,576	65,428	853	1.32%

Adjustments to the IESO Purchases

In its 2010 Cost of Service Application, EB-2009-0271, Oakville Hydro developed a weather normalized load forecast using a multivariate regression model that incorporated normalized historical load, weather, calendar related events and economic activity. In order to normalize historical load, Oakville Hydro made adjustments to reflect the loss of two large customers[1]. One

[1] 2010 Cost of Service Application, EB-2009-0271, Exhibit 3, Tab 2, Schedule 1, Pages 14 and 15.

customer became a metered market participant on May 1, 2002 and was no longer a customer of Oakville Hydro. Historical load was adjusted by removing this customer's load from the historical load. The second customer had reduced its operations in 2004 and, as a result, was reclassified from the Large Use class to the General Service greater than 1,000 kW class. Historical load was adjusted by replacing the actual historical load with the average load that this customer consumed after its restructuring.

In its 2010 Cost of Service Application, Oakville Hydro made further adjustments to the load forecast generated by the multivariate regression model to reflect the forecasted reduction in customer consumption levels in the General Services rate classes in the 2009 Bridge Year and 2010 Test Year as a result of the economic recession[2]. Prior to 2008, the Independent Electricity System Operator ("IESO") Control Room was fed through two feeders, one of which was owned by Oakville Hydro. However, in mid-2008 the IESO discontinued the use of Oakville Hydro's feeder. In May 2009, a large industrial plastics manufacturer who consumed a large amount of energy ceased operations. The premises are now occupied by another company; however the amount of energy consumed is a small fraction of that consumed by the previous customer. In 2010, a large automotive parts manufacturing company ceased operations and the premises continue to be vacant.

During the discovery process, Oakville Hydro produced multiple forecasts using alternative methods of forecasting the impact of load reductions. In response to Energy Probe interrogatories, Oakville Hydro produced a forecast by removing the historical load for the customers that were impacted by the economic recession and using historical data for the period beginning January 2002[3]. This model resulted in a good statistical fit with a Multiple R statistic of 96%. Oakville Hydro then added the estimated load for those customers impacted by the

[2] 2010 Cost of Service Application, EB-2009-0271, Exhibit 3, Tab 2, Schedule 1, Pages 32 to 46.
[3] Response to Energy Probe Interrogatory number 41(f), EB-2009-0271 and Energy Probe Clarification Question number 6(e).

recession to the forecast generated by the multivariate regression model to derive its 2009 Bridge Year and 2010 Test Year load forecasts.

In preparing its 2014 load forecast, Oakville Hydro has used a similar regression analysis methodology to that used in its previous cost of service rate application to determine a prediction model. Oakville Hydro reduced customer load by removing the historical load for the customers that were impacted by the economic recession. In addition, Oakville made adjustments for its wholesale market participant and the impacts of Conservation and Demand Management ("CDM") amounts, which is discussed further in the section on Multivariate Regression Model in this exhibit. The results are summarized in Table 3-3, Adjustments to IESO Purchases.

Table 3-3: Adjustments to IESO Purchases

Year	IESO Invoice	Loss of Large Use Customers	Loss of GS Customers	Wholesale Market	CDM	Adjusted Purchases
2002	1,808,746,161	(310,289,265)	(66,426,556)	-	-	1,432,030,340
2003	1,685,404,396	(216,768,576)	(70,697,114)	-	-	1,397,938,706
2004	1,715,537,080	(213,435,317)	(73,726,510)	-	-	1,428,375,252
2005	1,641,734,320	(42,813,078)	(71,817,588)	-	-	1,527,103,654
2006	1,557,023,459	-	(65,758,039)	-	11,731,774	1,502,997,193
2007	1,603,485,901	-	(66,453,368)	-	18,462,097	1,555,494,630
2008	1,573,748,750	-	(34,543,781)	-	13,257,912	1,552,462,881
2009	1,529,384,609	-	(17,499,013)	-	17,504,588	1,529,390,185
2010	1,598,682,854	-	(11,926,976)	-	22,523,751	1,609,279,628
2011	1,583,988,523	-	(1,039,538)	-	25,647,609	1,608,596,595
2012	1,589,423,311	-	-	4,125,986	32,051,941	1,625,601,238

Multivariate Regression Model

Oakville Hydro has been monitoring and where practical, adapting with the evolution of load forecasting for electricity distributors in Ontario and has noted that a number of distributors have produced class-specific load forecasts. Oakville Hydro is committed to the improvement of its load forecasting methodology and, in preparing its Application, Oakville Hydro explored its ability to forecast class-specific loads. Although Oakville Hydro estimates unbilled consumption by customer class each month, the class-specific sales models for the Residential and General Service less than 50 kW customer classes were not statistically strong with an R-Square of 63% and 67% respectively. Therefore, Oakville Hydro has continued to work with a modeling approach using total system energy purchases.

With this modeling approach, Oakville Hydro's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather, days in the month and customer data. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Lastly, the forecast of billed energy by rate classification is developed based on a forecast of customer numbers and historical usage patterns per customer.

For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate classification is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate classification is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to the energy forecast based on the historical relationship between kW and kWh. In addition, the billed energy by rate classification is adjusted in 2013 and 2014 to reflect the four year licensed CDM targets (i.e. 2011 to 2014) assigned to Oakville Hydro.

Conservation and Demand Management Impacts

In its Decision with Reasons on Hydro One Networks Inc.'s ("Hydro One") 2011 and 2012 Transmission Revenue Requirement and Rates Application, the Board instructed Hydro One to work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA[4]. On May 28, 2012, Hydro One filed the results of this study as Exhibit A-15-2 to its 2013 and 2014 Transmission Revenue Requirement Application[5]. In the study, Hydro One identified two methodologies that are commonly used in North America. The first is an implicit methodology where actual load data is used to generate the forecast and then future incremental CDM impacts are subtracted from the forecast. The second is an explicit methodology where historical CDM savings are first added back to the historical load. The resulting forecast is then adjusted by subtracting the past energy and future energy savings from the forecast. In preparing its load forecast Oakville Hydro tested both the implicit and explicit methodologies.

To test the implicit methodology, the historical CDM savings was used as an explanatory variable in the multivariate regression model and the forecasted CDM impacts were subtracted from the results. This methodology provided positive correlation between load growth and CDM savings. This result is an unintuitive result as one would expect that CDM activities would be negatively correlated with load growth. This unintuitive result may be explained by the fact load has grown at a faster rate than CDM savings in Oakville Hydro's service area.

To test the explicit methodology, the historical CDM savings were then added back to the load and a load forecast was determined before the impact of CDM savings. Then the load forecast was adjusted in 2013 and 2014 by subtracting all past and future energy savings from the 2013 and 2014 forecast before CDM savings. Oakville Hydro has used a similar method to in its load forecast modeling with adjustments intended to address the concerns raised in the 2013 cost of

[4] Decision with Reasons, EB-2010-002, Pages 6 and 7.
[5] Hydro One Networks Inc., 2013 and 2014 Transmission Revenue Requirement Application, EB 2012-0031.

service applications regarding the impact of CDM programs. As noted in the Filing Requirements, dated July 17, 2013, although it is recognized that the CDM programs in a year are not in effect for the full year the CDM results reported by the OPA are annualized. In light of this, Oakville Hydro is proposing that it is appropriate to use the methodology introduced by Board staff in London Hydro's cost of service application, EB-2012-0146/EB-2012-0380 in order to estimate the impact of CDM on historical load. In its interrogatories, Board staff proposed a methodology for implementing the half-year rule for London Hydro's CDM variable and provided an enhanced version of London Hydro's load forecast excel model setting out the calculations.[6] Oakville Hydro has used the methodology proposed by Board staff to estimate the impact of its 2006 to 2012 CDM savings in order to add back the impact of CDM to actual load data.

Purchased KWh Load Forecast – Excluding CDM Impact

An equation to predict total system purchased energy is developed using a multivariate regression model with the following independent variables:

- weather (heating and cooling degree days as measured by the number of degrees Celsius that the mean temperature was above or below 18°C).
- days in month
- number of customers
- day-light hours.

The regression model uses monthly kWh and monthly values of independent variables from January 2002 to December 2012 to determine the monthly regression coefficients. This provides 132 monthly data points, which represents a reasonable data set for use in a regression analysis. However, in accordance with the Board's Filing Requirements, Oakville Hydro has forecasted

[6] Board staff interrogatory number 22, London Hydro Cost of Service Application, EB-2012-0146/EB-2012-0380.

purchases assuming weather normal conditions based on a 10-year average and a 20-year trend of weather data. Oakville Hydro submits that it is appropriate to analyze the impact of weather based on the 10-year average beginning January 2003 on energy consumption to derive the average weather conditions to be used in the regression analysis.

Oakville Hydro tested a number of other drivers of year-over-year changes in Oakville Hydro's load growth but removed those that produced an unintuitive correlation or those that were statistically insignificant from the final regression model. Those variables that were tested and subsequently removed from the model were minimum temperature, maximum temperature, mean temperature, Ontario Real GDP, population, number of peak hours, and commodity price.

The following outlines the prediction model used by Oakville Hydro to predict weather normal purchases for 2013 and 2014 excluding the impact of CDM:

Oakville Hydro's Monthly Predicted kWh Purchases:

= Heating Degree Days (HDD) *19,073

+ Cooling Degree Days (CDD) * 252,726

+ Number of days in the Month (Days) * 3,389,180

- Spring Fall Flag * 4,699,953

+ Number of Customers (Customers) * 1,234

- Daylight hours * 27,620

- Intercept of 49,626,246

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. Weather data from the Toronto Lester B. Pearson International Airport was used.

b) The calendar provided information related to number of days in the month.

c) The spring fall flag applies to the months of March, April, May, September, October and November.

d) The number of customers was based on historical information from Oakville Hydro's billing system.

e) The number of daylight hours are the required lighting times established in the Board approved street lighting load shape template.

The prediction formula has the following statistical results:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	96.8%
R Square	93.6%
Adjusted R Square	93.3%
Standard Error	3575446.314
Observations	132

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	2.35541E+16	3.92569E+15	307.08266	2.76998E-72
Residual	125	1.59798E+15	1.27838E+13		
Total	131	2.51521E+16			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	(49,626,246.15)	12,871,824.16	(3.86)	0.00	(75,101,183.69)	(24,151,308.62)
HDD	19,073.59	2,538.39	7.51	0.00	14,049.81	24,097.37
CDD	252,726.15	11,651.13	21.69	0.00	229,667.12	275,785.19
Days	3,389,180.20	402,054.71	8.43	0.00	2,593,464.02	4,184,896.37
Spring Fall Flag	(4,699,953.37)	873,218.91	(5.38)	0.00	(6,428,161.96)	(2,971,744.78)
Customers	1,234.82	64.80	19.05	0.00	1,106.56	1,363.07
Daylight hours	(27,620.13)	7,875.82	(3.51)	0.00	(43,207.36)	(12,032.91)

The annual results of the prediction formula compared to the actual annual purchases, excluding CDM impacts, from 2002 to 2012 are shown in the chart below. The chart illustrates that the prediction formula is reasonable with an Adjusted R Square of 93.6% which is statistically significant.

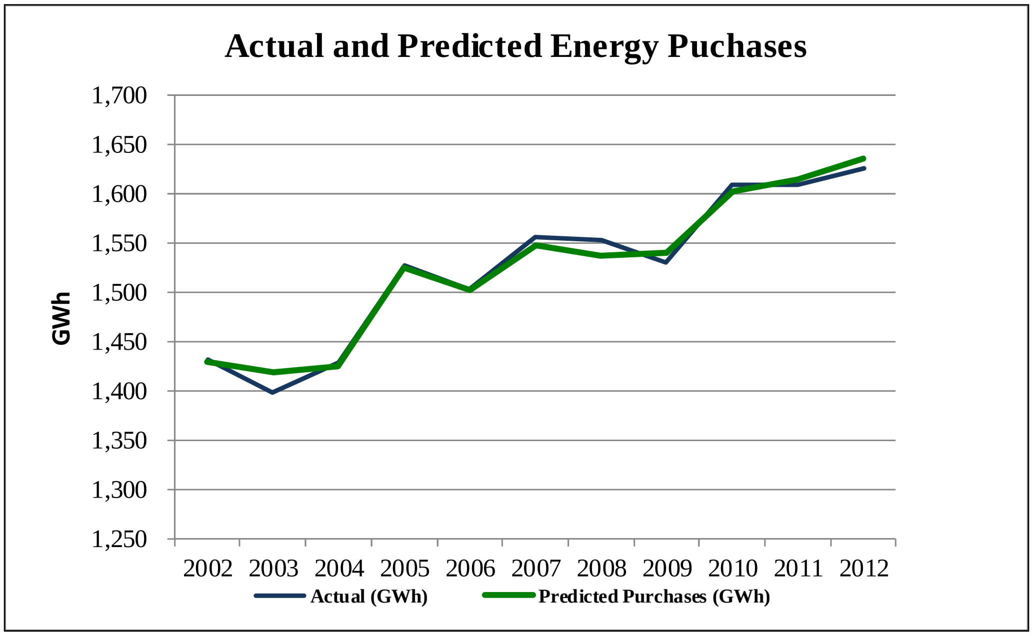


Table 3-4, Forecast Summary Excluding CDM Impacts, provides the data applicable to the above chart. In addition, the predicted total system purchases, excluding the impact of CDM activities, for Oakville Hydro are provided for 2013 and 2014. For 2013 and 2014 the system purchases reflect a weather normalized forecast for the full year. In addition, values for 2014 forecasts are provided with a 10-year average and a 20 year average assumption for weather normalization.

Table 3-4: Forecast Summary Excluding CDM Impacts

Year	Actual (GWh)	Predicted Purchases (GWh)
2002	1,432	1,428
2003	1,398	1,418
2004	1,428	1,424
2005	1,527	1,524
2006	1,503	1,502
2007	1,555	1,547
2008	1,552	1,536
2009	1,529	1,540
2010	1,609	1,601
2011	1,609	1,613
2012	1,626	1,635
2013	10 Year HDD/CDD	1,620
2014	10 Year HDD/CDD	1,630
2014	20 Year HDD/CDD	1,633

The weather normalized amount for 2014 is determined by using 2014 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 2003 to December 2012 (i.e. 10 years). The 2014 weather normalized 10 year average value represents the average heating degree days and cooling degree days that occurred from January 2003 to December 2012. The 2014 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1993 to December 2012.

The weather normalized 10-year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The 10-year average has been used as this is more consistent with the period of time over which the regression analysis was conducted.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast, excluding the impact of CDM activities, is adjusted by a historical loss factor. This adjustment has been made by Oakville Hydro using the average loss factor from 2002 to 2012 of 1.040 applied to each year. With this average loss factor the total weather normalized billed energy will be 1,577 GWh for 2013 and 1,567 GWh for 2014 before the adjustment for CDM discussed below.

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in Table 3-5, Historical Number of Customers/Connections at Year-End.

Table 3-5: Historical Number of Customers/Connections at Year-End

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Street Lights	Sentinel Lights	Unmetered Loads	Total
2002	44,243	4,010	756	17	13,948	271	615	63,861
2003	46,192	4,249	756	16	14,431	248	629	66,522
2004	48,272	4,395	758	16	14,828	244	642	69,156
2005	49,953	4,539	760	16	15,261	243	658	71,431
2006	51,485	4,614	774	16	15,571	241	661	73,363
2007	52,971	4,701	781	17	15,890	240	669	75,270
2008	54,636	4,809	813	17	16,025	237	675	77,212
2009	56,419	4,888	854	18	16,286	183	679	79,327
2010	56,923	4,897	871	17	16,598	179	665	80,150
2011	57,796	4,923	878	16	16,828	177	673	81,291
2012	58,286	4,911	893	16	17,113	167	676	82,062

From the historical customer/connection data the growth rates in customers/connections can be evaluated. The growth rates are provided in Table 3-6, Customer/Connection Percentage Growth Rates. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2002 to 2012 and from 2010 to 2012.

Table 3-6: Customer/Connection Percentage Growth Rates

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	Street Lights	Sentinel Lights	Unmetered Loads	Total
2003	1.0441	1.0594	1.0007	0.9412	1.0347	0.9151	1.0217	1.0417
2004	1.0450	1.0345	1.0030	1.0000	1.0275	0.9839	1.0205	1.0396
2005	1.0348	1.0327	1.0025	1.0000	1.0292	0.9959	1.0257	1.0329
2006	1.0307	1.0165	1.0182	1.0000	1.0203	0.9918	1.0044	1.0270
2007	1.0289	1.0190	1.0086	1.0625	1.0205	0.9959	1.0116	1.0260
2008	1.0314	1.0228	1.0412	1.0000	1.0084	0.9875	1.0090	1.0258
2009	1.0326	1.0165	1.0504	1.0588	1.0163	0.7722	1.0063	1.0274
2010	1.0089	1.0018	1.0199	0.9444	1.0192	0.9781	0.9794	1.0104
2011	1.0151	1.0084	1.0080	0.9412	1.0139	0.9888	1.0120	1.0142
2012	1.0087	0.9945	1.0171	1.0000	1.0169	0.9435	1.0045	1.0095
Geomean - 10 Year	1.0280	1.0205	1.0168	0.9940	1.0207	0.9527	1.0094	1.0254
Geomean - 3 Year	1.0109	1.0016	1.0150	0.9615	1.0166	0.9700	0.9985	1.0114

Oakville Hydro has based its forecast on the current three year trend for all classes except for the General Service > 1,000 kW class. The total amount of residential development lands has declined and growth is expected to continue at current rate of approximately 1% per year. In addition, the growth in the number of 2008 and 2009 General Service >50 kW and General Service >1,000 kW customers is inflated as a result of the construction of a large retail and entertainment complex in 2008. The number of General Service > 1,000 customers is not expected to change as the number of customers in this rate class has been declining since 2009 and Oakville Hydro is not aware of any new customers of this size. Oakville Hydro's forecasted number of customers and connections at year-end for the 2013 Bridge Year and 2014 Test Year based on historical data are provided in Table 3-7.

Table 3-7: Forecasted Customers/Connections at Year-End

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Street Lights	Sentinel Lights	Unmetered Loads	Total
2013	58,922	4,919	906	16	17,398	162	675	82,998
2014	59,565	4,926	920	16	17,688	157	674	83,946

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. Table 3-8, Historical kWh Usage, provides the average annual usage per customer by rate classification from 2002 to 2012.

Table 3:8: Historical kWh Usage

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Street lights	Sentinel Lights	Unmetered Loads
2002	11,888	36,281	658,862	9,270,369	535	455	7,069
2003	10,495	33,079	664,751	11,015,798	752	651	6,039
2004	10,681	33,422	720,453	10,947,330	764	648	6,945
2005	11,409	37,022	741,991	10,434,254	686	613	6,768
2006	10,950	36,852	716,635	9,940,436	687	595	6,461
2007	10,809	36,997	729,859	9,622,417	683	614	5,876
2008	10,435	36,573	721,983	8,580,129	684	573	5,803
2009	10,052	34,979	692,488	7,322,280	681	732	5,798
2010	10,600	34,783	705,175	8,291,850	684	704	5,739
2011	10,393	34,089	701,276	9,285,748	689	689	5,443
2012	10,624	33,042	680,806	9,338,243	691	717	5,469

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in Table 3-9. The geometric mean growth rate has also been shown.

Table 3-9: Historical Percentage Growth Rates

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Street lights	Sentinel Lights	Unmetered Loads
2003	0.8828	0.9117	1.0089	1.1883	1.4062	1.4316	0.8543
2004	1.0177	1.0104	1.0838	0.9938	1.0153	0.9943	1.1500
2005	1.0681	1.1077	1.0299	0.9531	0.8977	0.9467	0.9745
2006	0.9598	0.9954	0.9658	0.9527	1.0024	0.9712	0.9547
2007	0.9871	1.0039	1.0185	0.9680	0.9930	1.0309	0.9094
2008	0.9654	0.9885	0.9892	0.8917	1.0022	0.9331	0.9876
2009	0.9632	0.9564	0.9591	0.8534	0.9949	1.2777	0.9991
2010	1.0546	0.9944	1.0183	1.1324	1.0052	0.9617	0.9898
2011	0.9804	0.9800	0.9945	1.1199	1.0071	0.9795	0.9484
2012	1.0222	0.9693	0.9708	1.0057	1.0027	1.0395	1.0047
10 Year Geomean	0.9888	0.9907	1.0033	1.0007	0.9906	1.0107	0.9747

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2012 usage and the resulting usage forecast is in Table 3-10.

Table 3-10: Forecasted Annual kWh Usage Per Customer/Connection

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Street lights	Sentinel Lights	Unmetered Loads
2013	10,402	32,735	683,044	9,345,067	684	724	5,330
2014	10,276	32,430	685,286	9,351,888	678	732	5,195

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3-7 by the forecast of annual usage per customer/connection from Table 3-10. The resulting non-normalized weather billed energy forecast is shown in Table 3-11.

Table 3-11: Billed Energy Forecast – Non-Normalized Weather

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Street lights	Sentinel Lights	Unmetered Loads	Total
2013	609,579,178	160,887,107	614,532,000	149,069,218	11,811,086	119,132	3,600,460	1,549,598,182
2014	608,791,917	159,639,363	625,795,060	148,276,366	11,894,652	116,788	3,504,020	1,558,018,165

The non-normalized weather billed energy forecast has been determined requires an adjustment in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 1,550 GWh for the 2013 Bridge Year and 1,558 GWh for the 2014 Test Year.

The difference between the non-normalized and normalized forecast adjustments is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for Oakville Hydro for the 2007 Cost Allocation Study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 3-12: Weather Sensitivity By Rate Class in kWh

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Street lights	Sentinel Lights	Unmetered Loads	Total
2013	3,538,588	840,550	2,853,871	129,801	0	0	0	7,362,811
2014	3,981,303	939,591	3,273,998	145,452	0	0	0	8,340,344

For the General Service > 50 kW class the weather sensitivity amount of 80% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. Oakville Hydro agrees with this position but also submits that the weather sensitivity for the GS < 50 kW classes should be higher than the General Service > 50 kW class. As a result, Oakville Hydro has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 80%, or 90%.

The difference between the non-normalized and normalized forecast 2013 and 2014 has been assigned on a *pro rata* basis to each rate classification based on the above level of weather sensitivity. The non weather-normalized forecast in Table 3-11 is adjusted by the allocated weather sensitivity amount in Table 3-12 to derive the normalized load forecast. Table 3-13 provides the weather normalized forecast, excluding CDM adjustments, for the 2013 Bridge Year and the 2014 Test Year.

Table 3-13: Normalized kWh, Excluding CDM Adjustments

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Street lights	Sentinel Lights	Unmetered Loads	Total
2013	616,372,052	161,063,753	615,129,966	149,096,416	11,811,086	119,132	3,600,460	1,557,192,865
2014	616,339,127	159,863,885	626,575,420	148,311,037	11,894,652	116,788	3,504,020	1,566,604,928

CDM Adjustment for the Load Forecast for Distributors

As discussed previously, Oakville Hydro added the impact of CDM from 2006 to 2012 back to the actual load and forecasted the expected level of electricity purchases in the absence of any CDM initiatives. The forecasted energy purchases before CDM savings for the 2013 Bridge Year and the 2014 Test Year in Table 3-13 are then adjusted to reflect actual and forecasted CDM activities to produce a forecast which reflects CDM savings.

As noted in the Filing Requirements, dated July 17, 2013, although it is recognized that the CDM programs in a year are not in effect for the full year the CDM results reported by the OPA are annualized. Appendix 2-I of the Board's Filing Requirements Chapter 2 Appendices provides one approach for calculating the aggregate amounts for the LRAMVA and the corresponding CDM adjustment to the load forecast. However, this approach is based on the assumption that the impacts of CDM programs are already implicitly reflected in the actual data for historical years. Therefore, Oakville Hydro has then deducted the full impact of the 2006 to 2012 programs from its 2013 and 2014 proposed load forecast. Oakville Hydro has used the methodology proposed in Appendix 2-I to estimate the impact of 2013 and 2014 CDM programs on the 2013 and 2014 proposed load forecast based on the assumption that Oakville Hydro will achieve its targeted MWh savings of 74.06. Oakville Hydro deducted 50% of the 2013 and 2014 CDM impacts in the year of the program. The following tables provide the impact of Oakville Hydro's CDM activities on billed energy.

Appendix 2-I

Load Forecast CDM Adjustment Work Form (2014)

4 Year (2011-2014) kWh Target:
74,060

	2011	2012	2013	2014	Total
2011 CDM Programs	9.13%	9.12%	9.12%	9.01%	36.38%
2012 CDM Programs		9.12%	9.12%	7.97%	26.21%
2013 CDM Programs			12.47%	12.47%	24.94%
2014 CDM Programs				12.47%	12.47%
Total in Year	**9.13%**	**18.25%**	**30.71%**	**41.91%**	**100.00%**
		kWh			
2011 CDM Programs	6,762.41	6,756.96	6,753.64	6,671.54	26,944.55
2012 CDM Programs		6,756.96	6,756.96	5,900.00	19,413.93
2013 CDM Programs			9,233.84	9,233.84	18,467.68
2014 CDM Programs				9,233.84	9,233.84
Total in Year	**6,762.41**	**13,513.93**	**22,744.44**	**31,039.22**	**74,060.00**

Weight Factor for Inclusion in CDM Adjustment to 2014 Load Forecast

	2011	2012	2013	2014	
Weight Factor for each year's CDM program impact on 2014 load forecast	**1**	**1**	**1**	**0.5**	Utility can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Persistence of 2011 CDM programs for the full year of 2012 means that all of 2011 CDM impact is assumed to be in the base forecast before the CDM Adjustment*	*50% of 2012 CDM impact is assumed reflected in base forecast based on 1/2 year rule.*	*Full year impact of 2013 CDM programs on adjustment for 2014 load forecast*	*Only 50% of 2014 CDM impact is used based on a half year rule*	

Table 3-14, Impact of 2011 to 2014 CDM Programs (MWh)

CDM Savings	2011 Actual	2012 Actual	2013 Forecast	2014 Forecast	Total
% Savings					
2011 Actual	9.1%	9.1%	9.1%	9.0%	36.4%
2012 Actual		10.60%	10.6%	10.6%	31.8%
2013 Forecast			10.6%	10.6%	21.2%
2014 Forecast				10.6%	10.6%
Total	9.1%	19.7%	30.3%	40.8%	100.0%
MWh Savings					
2011 Actual	6,762	6,757	6,754	6,672	26,945
2012 Actual		5,977	5,977	5,900	17,855
2013 Forecast			9,754	9,754	19,507
2014 Forecast				9,754	9,754
Total	6,762	12,734	22,485	32,079	74,060

Table 3-15, CDM Impacts – Half-year Rule

CDM Savings	2013 Forecast	2014 Forecast
MWh Savings		
Pre-2011 Programs (Cumulative)	19,821	18,957
2011 Programs	6,754	6,672
2012 Programs	5,977	5,900
2013 Programs	4,877	9,754
2014 Programs	-	4,877
Total	37,429	46,159

In accordance with the Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003, issued April 26, 2012, it is Oakville Hydro's understanding that as part of this application expected CDM savings in 2014 from 2011, 2012, 2013 and 2014 programs will need to be established for LRAM variance accounts purposes. It is also Oakville Hydro's understanding that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected the net level of savings will be used for LRAM calculations. As a result, it is Oakville Hydro's view the units used for the 2014

LRAM variance account should also be on a net basis. Based on the net information in Table 3-15, Oakville Hydro expects to achieve 46,159 in cumulative net MWh savings in 2014 from CDM programs. For LRAM variance account purposes, Table 3-16 outlines how this expected savings has been allocated to rate class using the 2014 information from Table 3-15. The expected kW saving has also been provided for those classes billed distribution charges on a kW basis using the average kW/KWh factors from Table 3-20.

Table 3-16, CDM Impacts by Rate Classification (MWh)

Rate Class	2013 kWh	2013 kW	2014 kWh	2014 kW
Residential	15,786	-	17,324	-
GS < 50 kW	1,731	-	2,071	-
GS > 50 kW	19,046	50	22,777	60
GS > 1000 kW	866	2	1,035	3
Streetlighting	-		2,952	8
Total	37,429	52	46,159	63

Embedded Distributor

In August 2013, Milton Hydro Distribution Inc. ("Milton Hydro") became an Oakville Hydro customer in the General Service rate class. On July 19, 2013, Milton Hydro provided Oakville Hydro with its load forecast in kW for the 2014 Test Year, found in Appendix A. Since Milton Hydro's forecasted load does not form a part of Oakville Hydro's historical load data, Milton Hydro's forecast has been converted to 33,729,600 kWh and has been added to the forecasted load for the applicable portion of the 2013 Bridge Year and the 2014 Test Year in a new Embedded Distributor rate class. Tables 3-17 and 3-18 summarize the impacts of normalization, CDM activities and the addition of Milton Hydro as an Embedded Distributor to the forecasted consumption for the 2013 Bridge Year and the 2014 Test Year.

Municipal Street Lighting

Oakville Hydro met with representatives from the Town of Oakville on June 24, 2013 to explain the regulatory process that is followed in Ontario in order to approve distribution rates, including the Board's Cost Allocation Model and how it is used to develop charges for Unmetered Loads. A follow-up meeting was held on August 29, 2013 to discuss the distribution system in the Town of Oakville and the number of Street Lighting connections and to present Oakville Hydro's preliminary allocation of costs to the Street Lighting rate class. At the meeting, representatives from the Town of Oakville shared their plans for the conversion of existing street lights to LED lights beginning in 2014. As a result of this discussion, Oakville Hydro has re-estimated the load profile for street lights in the Town of Oakville for the 2014 Test Year.

Table 3-17: 2013 Weather Normalized Billed Energy Forecast (GWh)

Rate Class	Non-normalized Billed Energy	Adjustment for Weather Normalization	Normalized Billed Energy	CDM Adjustment & Embedded Distributor	Weather Normal Billed Energy Forecast (GWh)
Residential	609.6	3.5	613.1	(15.8)	597.3
General Service < 50 kW	160.9	0.8	161.7	(1.7)	160.0
Unmetered	3.6	-	3.6	-	3.6
General Service > 50 kW	614.5	2.9	617.4	(19.0)	598.3
General Service > 1,000 kW	149.1	0.1	149.2	(0.9)	148.3
Embedded Distributor	-	-	-	8.4	8.4
Sentinel Lighting	0.1	-	0.1	-	0.1
Street Lighting	11.8	-	11.8	-	11.8
Total	1,549.6	7.4	1,557.0	(29.0)	1,528.0

Table 3-18: 2014 Weather Normalized Billed Energy Forecast.

Rate Class	Non-normalized Billed Energy	Adjustment for Weather Normalization	Normalized Billed Energy	CDM Adjustment & Embedded Distributor	Weather Normal Billed Energy Forecast
Residential	608.8	4.0	612.8	(17.3)	595.4
General Service < 50 kW	159.6	0.9	160.6	(2.1)	158.5
Unmetered	3.5	-	3.5	-	3.5
General Service > 50 kW	625.8	3.3	629.1	(22.8)	606.3
General Service > 1,000 kW	148.3	0.1	148.4	(1.0)	147.4
Embedded Distributor	-	-	-	33.7	33.7
Sentinel Lighting	0.1	-	0.1	-	0.1
Street Lighting	11.9	-	11.9	(3.0)	8.9
Total	1,558.0	8.3	1,566.4	(12.4)	1,553.9

Billed kW Load Forecast

The General Service > 50 kW, General Service > 1,000 kW, Sentinel Lighting and Street Lighting rate classifications are billed based upon kW demand rather than kWh consumed. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW. The Embedded Distributor rate classification is also billed based upon kW demand, however, the 2013 Bridge Year and 2014 Test Year estimates are based on the load forecast provided by Milton Hydro. Table 3-19 and 3-20 provided the Historical kW by rate classification and the historical relationship between kW and kWh.

Table 3-19: Historical kW By Rate Class

Year	General Service > 50 to 999	General Service > 1000 kW	Street Lighting	Sentinel Lights
2002	1,347,369	547,521	15,926	342
2003	1,509,048	480,074	30,232	449
2004	1,645,568	585,688	31,103	439
2005	1,548,601	469,035	29,363	414
2006	1,518,283	467,246	29,890	399
2007	1,564,120	461,503	30,296	409
2008	1,614,129	411,997	30,509	377
2009	1,564,795	357,797	30,957	372
2010	1,595,879	370,035	31,713	350
2011	1,590,500	338,497	32,425	339
2012	1,631,952	328,299	32,927	332

Table 3-20: Historical Relationship between kW and kWh

Year	General Service > 50 to 999 kW	General Service > 1000 kW	Street Lighting	Sentinel Lights
2002	0.2706%	0.3474%	0.2134%	0.2778%
2003	0.3002%	0.2724%	0.2784%	0.2778%
2004	0.3012%	0.3344%	0.2746%	0.2778%
2005	0.2745%	0.2809%	0.2806%	0.2778%
2006	0.2737%	0.2938%	0.2792%	0.2778%
2007	0.2745%	0.2821%	0.2793%	0.2778%
2008	0.2750%	0.2825%	0.2783%	0.2778%
2009	0.2646%	0.2715%	0.2793%	0.2778%
2010	0.2598%	0.2625%	0.2792%	0.2778%
2011	0.2583%	0.2278%	0.2796%	0.2778%
2012	0.2684%	0.2197%	0.2785%	0.2778%
5 Year Averag	0.2622%	0.2238%	0.2791%	0.2778%

Oakville Hydro has applied the five-year average rather than the 11-year average, to the normalized billed energy forecast, adjusted for CDM to derive the forecast of kW by rate class in order to reflect more recent trends resulting from CDM programs. For the Embedded Distributor rate classification, the forecasted demand was provided by Milton Hydro. Table 3-21 provides the forecasted billing determinants for the 2013 Bridge Year and the 2014 Test Year for each rate classification.

Table 3-21: Forecasted Billing Determinants

Year	General Service > 50 to 999 kW	General Service > 1000 kW	Street Lighting	Sentinel Lights
2013	1,618,729	333,878	32,965	331
2014	1,649,361	332,139	33,198	324

Accuracy of the Load Forecast and Variance Analysis

Historical and Forecast Volumes, Customer Counts and Connections

Table 3-22 provides a summary of the kWh, kW, customer counts and connections by rate classification for the historical, Bridge and Test Years. For the 2013 Bridge Year and the 2014 Test Year, the kW are calculated based upon the historical relationship between kWh and kW and the customer counts are as at December 31st of each year for the historical, Bridge and Test Years.

Table 3-22: Historical and Forecasted Volumes and Customers (Including the Impact of CDM)

Rate Class	2008 Actual	2009 Actual	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Weather Normal	2014 Weather Normal
Residential								
Customers	54,636	56,419	58,617	56,923	57,796	58,286	58,922	59,565
kWh	559,480,721	555,127,459	557,127,208	597,295,732	588,575,028	600,534,935	597,332,133	595,449,114
General Service < 50 kW								
Customers	4,809	4,888	5,109	4,897	4,923	4,911	4,919	4,926
kWh	175,714,453	170,241,898	173,390,609	170,509,443	167,110,172	162,269,747	159,996,164	158,508,292
Unmetered Loads								
Connections	675	679	696	665	673	676	675	674
kWh	3,915,659	3,936,855	3,881,044	3,816,306	3,663,023	3,696,824	3,600,460	3,504,020
General Service > 50 to 999 kW								
Customers	813	854	833	871	878	893	906	920
kWh	593,404,108	584,084,594	594,844,951	602,895,003	602,311,205	603,821,865	598,339,440	606,291,782
kW	1,614,129	1,564,795	1,670,520	1,595,879	1,590,500	1,631,952	1,618,729	1,649,361
General Service > 1000 kW								
Customers	17	18	17	17	16	16	16	16
kWh	170,191,555	147,437,802	147,132,426	151,840,794	148,964,252	149,411,044	148,333,272	147,386,488
kW	411,997	357,797	353,675	370,035	338,497	328,299	333,878	332,139
Large Use >5000 kW								
Customers	1	1	-	-	-	-	-	-
kWh	60,236,729	1,377,628	-	-	-	-	-	-
kW	106,448	30,509	-	-	-	-	-	-
			-					
Embedded Distributor								
Customers	-	-	-	-	-	-	1	1
kWh	-	-	-	-	-	-	8,432,400	33,729,600
kW	-	-	-	-	-	-	36,000	72,000
Street lights								
Connections	16,025	16,286	16,783	16,598	16,828	17,113	17,398	10,404
kWh	10,963,488	11,085,581	11,730,313	11,356,779	11,596,323	11,824,926	11,811,086	8,943,095
kW	30,509	30,957	33,349	31,713	32,425	32,927	32,965	33,198
Sentinel Lights								
Connections	237	183	227	179	177	167	162	157
kWh	135,737	133,918	135,511	126,835	122,878	119,670	119,132	116,788
kW	377	372	389	350	339	332	331	324
Total								
Customer/Connections	77,212	79,328	82,281	80,150	81,291	82,062	82,999	76,664
kWh	1,574,042,450	1,473,425,735	1,488,242,062	1,537,840,892	1,522,342,881	1,531,679,011	1,527,964,086	1,553,929,178
kW from applicable classes	2,163,461	1,984,430	2,057,933	1,997,977	1,961,761	1,993,510	2,021,903	2,087,023

Table 3-23 provides a summary of the normalized kWh, kW, customer counts and connections by rate classification for the historical, Bridge and Test Years. The total system weather normalized kWh for the historical years are calculated as follows:

1. Calculate predicted purchases using actual HDD and CDD.
2. Calculate predicted purchases using weather normalized HDD and CDD (10-year average).
3. Calculate the difference between actual purchases calculated in step one and weather normal purchases based calculated in step two to derive the weather sensitive kWh.
4. Add or subtract the difference between actual weather purchases and weather normalized purchases to actual billed data to derive weather total system normalized kWh.
5. Allocated weather sensitive kWh to each rate class based upon the weather sensitivity by rate class.
6. Calculate weather normalized kW for the historical years based upon the historical relationship between kWh and kW.

Table 3-23: Weather Normalized Historical and Forecasted Volumes and Customers

Rate Class	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Weather Normal	2014 Weather Normal
Residential							
Customers	54,636	56,419	56,923	57,796	58,286	58,922	59,565
kWh	557,871,946	553,510,738	598,680,608	588,567,824	606,225,170	597,332,133	595,449,114
General Service < 50 kW							
Customers	4,809	4,888	4,897	4,923	4,911	4,919	4,926
kWh	175,294,276	169,874,573	170,540,501	167,124,795	163,811,578	159,996,164	158,508,292
Unmetered Loads							
Connections	675	679	665	673	676	675	674
kWh	3,915,659	3,936,855	3,816,306	3,694,151	3,727,960	3,600,460	3,504,020
General Service > 50 to 999 kW							
Customers	813	854	871	878	893	906	920
kWh	592,126,646	582,776,140	603,271,971	602,311,375	603,853,839	598,339,440	606,291,782
kW	1,552,502	1,527,985	1,581,724	1,579,205	1,583,249	1,568,791	1,589,641
General Service > 1000 kW							
Customers	17	18	17	16	16	16	16
kWh	169,927,737	147,139,063	152,622,417	148,962,445	150,398,492	148,333,272	147,386,488
kW	380,265	329,268	341,539	333,349	336,562	331,941	329,822
Large Use >5000 kW							
Customers	1	1	-	-	-	-	-
kWh	60,236,729	1,377,628	0	0	0	0	0
kW	106,448	2,363	0	0	0	0	0
Embedded Distributor							
Customers	-	-	-	-	-	1	1
kWh	0	0	0	0	0	8,432,400	33,729,600
kW	0	0	0	0	0	18,250	73,000
Street lights							
Connections	16,025	16,286	16,598	16,828	17,113	17,398	6,120
kWh	135,737	133,918	125,971	122,014	119,670	119,132	116,788
kW	377	372	350	339	332	331	324
Sentinel Lights							
Connections	237	183	179	177	167	162	157
kWh	10,963,488	11,085,581	11,356,779	11,596,323	11,824,926	11,811,086	8,943,095
kW	30,600	30,940	31,697	32,366	33,004	32,965	24,961
Total							
Customer/Connections	77,212	79,328	80,150	81,291	82,062	82,999	72,379
kWh	1,570,472,218	1,469,834,496	1,540,414,553	1,522,378,928	1,539,961,635	1,527,964,086	1,553,929,178
kW from applicable classes	2,070,191	1,890,929	1,955,310	1,945,258	1,953,148	1,952,278	2,017,748

Variance Analysis

Customer Counts and Connections

Oakville Hydro has had two major changes to the composition of its customer base over the period 2008 to 2013. In 2009, Oakville Hydro's one large use customer was reclassified to General Service Greater than 50 kW and, in August 2013, Oakville Hydro connected Milton Hydro as an embedded distributor.

Oakville Hydro is forecasting an increase in total customers, excluding street lighting and sentinel lighting, of 1,322 in the 2014 Test Year over to the 2012 actual customer number. This represents a one per cent increase in both the 2013 Bridge Year and the 2014 Test Year. As shown in the graph below, this is slightly higher than the trend (shown in red) from 2009 to 2012.

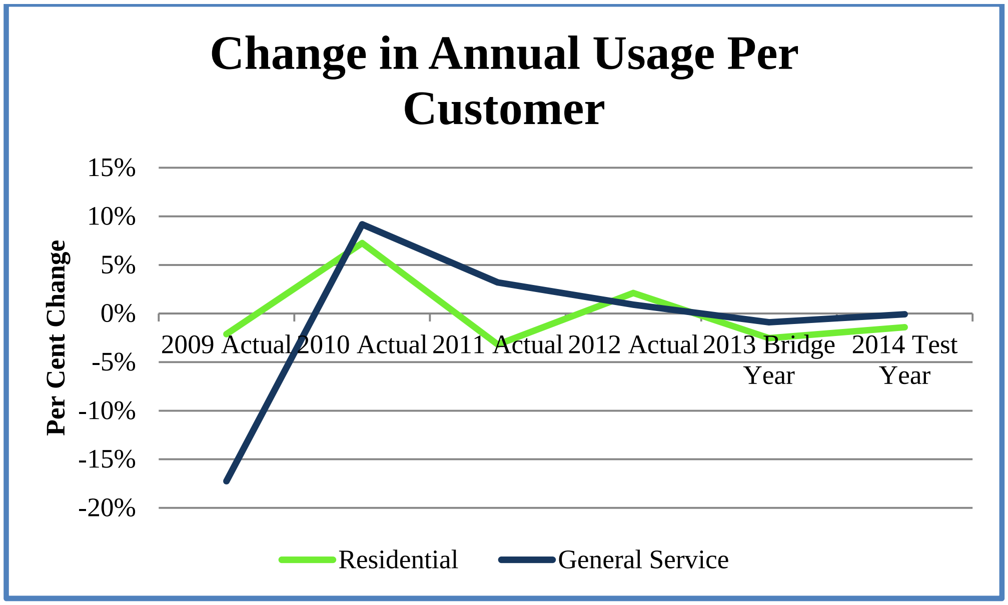
Average Annual Consumption

Table 3-24 provides the average consumption per customer/connection for five historical years, the 2010 Board Approved cost of service year, and the forecasted average consumption per customer/connection for the 2013 Bridge Year and the 2014 Test Year.

Table 3-24: Weather Normalized Average Annual kWh per Customer

Year	Residential	General Service < 50 kW	Unmetered	General Service > 50 kW	General Service > 1,000 kW	Large Use	Embedded Distributor	Setinel Lighting	Street Lighting
2008 Actual	10,023	36,113	5,767	714,266	9,995,749	60,236,729	-	675	682
2009 Actual	9,811	34,761	5,798	681,610	8,174,392	1,377,628	-	732	681
2010 Board Approved	9,505	33,939	5,578	714,028	8,654,849	-	-	598	699
2010 Actual	10,521	34,904	5,756	694,214	8,977,789	-	-	704	684
2011 Actual	10,186	33,831	5,505	674,481	9,310,153	-	-	689	689
2012 Actual	10,401	33,356	5,515	676,208	9,399,906	-	-	717	691
2013 Bridge Year	10,137	32,431	5,350	659,924	9,326,658	-	8,432,400	735	679
2014 Test Year	9,994	32,057	5,183	657,895	9,321,202	-	33,729,600	743	1,143

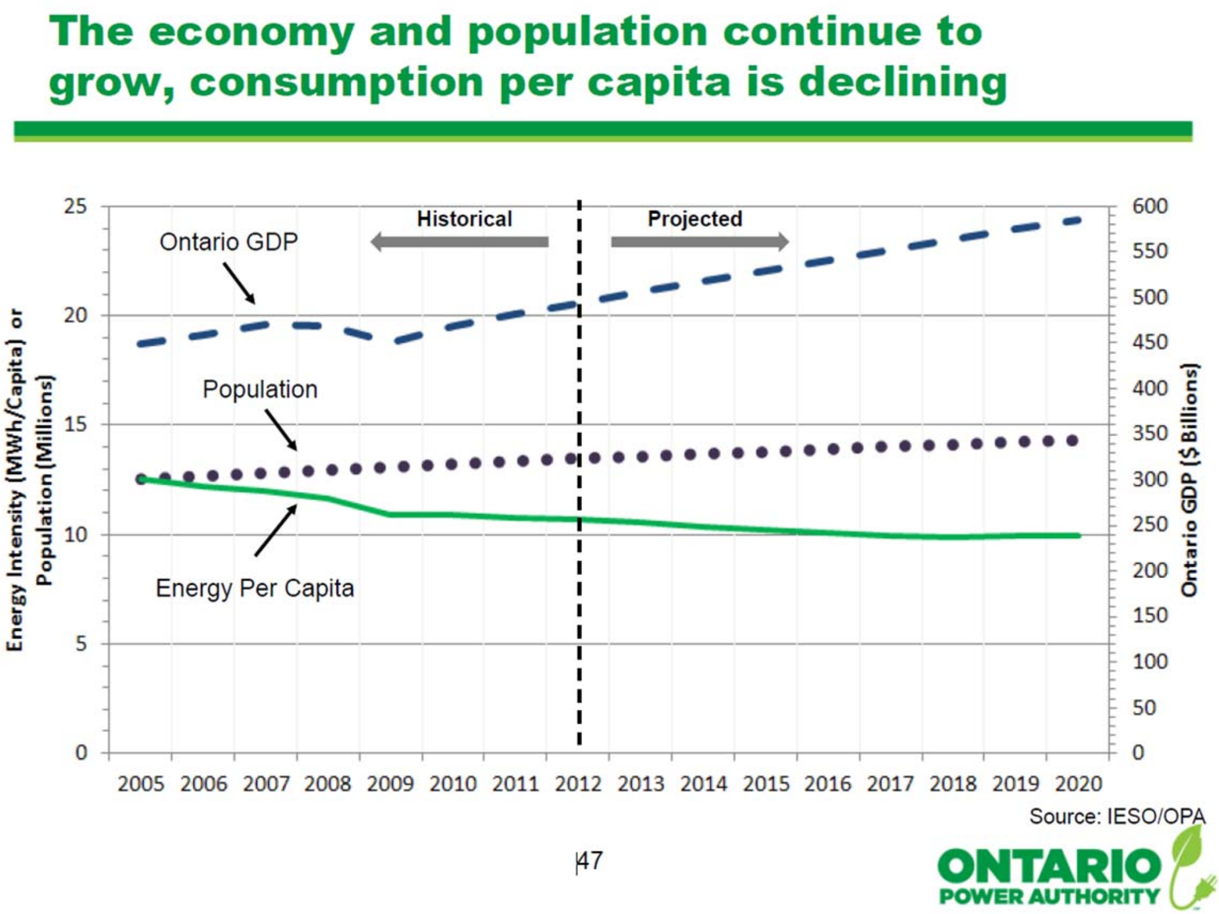
In 2009, the economic recession impacted the weather normalized average annual consumption for both Oakville Hydro's residential and its general service customer classes. In 2010, the economy strengthened and the average annual kWh per customer for the residential customers rebounded. However, the recovery for the general service customer classes was less prominent with the average annual consumption staying their pre-recession levels. Since 2010, the residential average annual consumption of the residential customers has decreased by one per cent from 10,521 kWh in 2010 to 10,401 kWh in 2012. The average annual consumption for the General Service < 50 kW rate class has decreased by four per cent from 34,904 kWh in 2010 to 33,356 kWh in 2012 while the General Service > 50 kW rate class has decreased by three per cent. In contrast, the annual consumption for the General Service > 50 kW rate class has increased to 9,399,906 kWh in 2012 from 8,977,789 kWh in 2010. However, the general service customers have not returned to their pre-recession levels. The following chart shows illustrates the changes in annual consumption per customer for the historical period and the forecasted change in annual consumption in the 2013 Bridge Year and the 2014 Test Year.

1 
Change in Annual Usage Per Customer
Per Cent Change
15%
10%
5%
0%
-5%
-10%
-15%
-20%
2009 Actual
2010 Actual
2011 Actual
2012 Actual
2013 Bridge Year
2014 Test Year
Residential
General Service

Oakville Hydro is forecasting the downward trend in the Residential and General Service less than 50 kW rate classes will continue in the 2013 Bridge Year and the 2014 Test Year. The forecasted decrease in the average consumption per customer is consistent with both the Ontario and US markets. On January 8, 2013, The Ontario Power Authority hosted a webinar on the *Future of Demand Growth.* In the webinar the Brattle Group, a consulting firm that provides economic, financial, strategic and regulatory services, made a presentation on the causes of the decrease in demand for electricity in the US. The Brattle Group concluded that "The drop in demand growth seems to be permanent, not transitory. The *new normal* may be growth at about half of the pre-recession values…".[7] According to the Brattle Group, there are five forces creating this new normal: a weak economy, demand-side management, codes and standards that promote energy efficiency, distributed generation and fuel switching caused by lower natural gas prices.

Consistent with this view, the Ontario Power Authority stated during the webinar that despite the fact that the economy and population continue to grow, consumption per capita is declining and that the Ontario electricity demand has been declining and is not expected to grow until at least 2020. In addition, natural conservation, codes and standards will contribute significantly to offset any growth. The following diagram illustrates the impact of conservation efforts and price impacts.

[7] The Future of Demand Growth, How Five Forces are Creating the New Normal, January 8, 2013, Slide 37.



Historical Board-approved vs. Historical Actual

As shown in Table 3-25, the historical actual billed consumption of 1,537.8 GWh for the 2010 Test Year was 3.3% higher than the Board-approved GWh of 1,488.2 while the historical actual weather normalized volumes were 3.5% higher than the Board-approved GWh. This can be partially attributed to the increase in consumption per customer in the residential rate class. The remainder of the variance can be attributed to the beginning of the recovery from the economic recession.

Table 3-25: Variance Analysis, Board Approved vs. Actual Billed Volumes

Year	Historical Weather Normal	Variance From Board Approved
2010 Board Approved	1,488.2	
2010 Actual	1,537.8	3.3%
2010 Weather Normalized	1,540.4	3.5%

Historical Actual - weather normalized vs. the preceding year's Historical Actual - weather normalized

Table 3-26 provides the year over year variance in historical weather normalized billed volumes. In November 2008 Oakville Hydro's Large Use customer reduced its production significantly. In addition, there were a number of plant closures in 2009 as result of the economic recession. This resulted in a decrease in the 2009 historical weather normalized volumes of 2.8% as compared to the 2008 weather normalized volumes. In 2010 the Ontario economy improved and volumes increased by 4.9% as compared to 2009 weather normalized volumes. In 2011 and 2012, Oakville Hydro experienced modest changes in its weather normalized volumes.

Table 3-26: Variance Analysis, Historical Actual vs. Historical

Year	Historical Weather Normal	Variance From Prior Year
2008	1,510.2	
2009	1,468.5	-2.8%
2010	1,540.4	4.9%
2011	1,522.4	-1.2%
2012	1,540.0	1.2%
2013 Bridge Year	1,527.3	-0.8%
2014 Test Year	1,555.1	1.8%

Historical Actual - weather normalized vs. the Forecasted - weather normalized

As shown in Table 3-26 above, Oakville Hydro is forecasting a decrease of 0.8% in weather normalized billed volumes in the 2013 Bridge Year as compared to 2012 historical actual weather normalized volumes. Oakville Hydro is forecasting an increase in weather normalized volumes of 1.8% in the 2014 Test Year as compared to the 2013 Bridge Year. Although Oakville Hydro is forecasting an increase of approximately 1% growth in the number of customers in its service territory in the 2013 Bridge Year and the 2014 Test Year the average consumption per customer is expected to continue to decline. Table 3-24 provides the historical average use per customer for the historical, Bridge and Test Years.

Operating Revenue Variance Analysis

Summary of Throughput Distribution Revenue Variances

Oakville Hydro's historical distribution revenue is calculated in accordance with section 2.1.5.4 of the Board's Electricity Reporting and Record Keeping Requirements. Distribution revenue for the 2013 Bridge Year is calculated based upon forecasted billing quantities and current rates. Distribution revenue for the 2014 Test Year is calculated based upon forecasted billing quantities and proposed rates. A summary of historical revenue by rate class is provided in Table 3-1.

Rate Adjustments

On March 14, 2011, the Board approved Oakville Hydro's application for an adjustment to its rates under the Board's Incremental Capital Module for the recovery of the costs associated with the design and construction of the Glenorchy Municipal Transformer Station in North Oakville, EB-2010-0104 effective May 1, 2011. On August 23, 2012, the Board approved Oakville Hydro's standalone application for the recovery of costs related to smart meter deployment, EB-2012-0193, through a Smart Meter Incremental Revenue Requirement ("SMIRR") rate rider. Prior to the approval of the SMIRR both the revenues and the costs associated with Oakville Hydro's smart meter deployment were recorded in regulatory deferral accounts. On September 1, 2012 Oakville Hydro began to recognize the revenues associated with the smart meter deployment.

Table 3-27 Summary of Distribution Revenue Variances below summarizes distribution revenue variances for the historical, bridge and test year (at existing rates). For comparative purposes Oakville Hydro has shown the per cent variance to the prior year including and excluding the revenues from the rate adjustment for the incremental capital claim and the SMIRR.

Table 3-27: Summary of Distribution Revenue Variances

	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Distribution Revenue Excluding SMIRR and ICM	31,136,649	29,806,975	30,872,620	32,072,265	31,755,747	32,848,413
% Variance	-	-4.27%	3.58%	3.89%	-0.99%	3.44%
Rate Adjustments	-	-	1,212,567	1,437,934	4,012,086	4,031,974
Distribution Revenue Including SMIRR and ICM	31,136,649	29,806,975	32,085,187	33,510,199	35,767,833	36,880,386
% Variance	-	-4.27%	7.64%	4.44%	6.74%	3.11%

Historical Throughput Distribution Revenue Variances:

The Board establishes distribution rates through periodic cost of service reviews and annual incentive regulation mechanism (“IRM”) adjustments. On April 30, 2010 the Board issued its Decision and Order approving Oakville Hydro’s 2010 Test Year revenue requirement of $31,136,649, EB-2009-0271. Since then, Oakville Hydro has applied for and received approval for annual mechanistic rate adjustments. In its 2011 IRM application (EB-2010-0104) Oakville Hydro also received approval for an incremental capital claim for the design and construction of the Glenorchy Municipal Transformer Station in North Oakville. On August 23, 2012, the Board approved Oakville Hydro’s stand-alone application for recovery of its costs related to smart meter deployment.

Distribution Revenue by Rate Class

Distribution revenue by rate classification for the historical, Bridge and Test years is provided in Table 3-28.

Table 3-28: Distribution Revenue by Rate Classification

Operating Revenues	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Bridge	2014 Test
Distribution Throughput Revenue						
Residential	$17,174,410	$17,594,797	18,241,865	$18,998,962	$20,553,737	$21,508,431
General Service < 50 kW	4,451,203	4,083,476	4,433,621	4,505,513	4,837,423	$3,997,189
Unmetered	136,242	146,426	132,889	136,384	139,533	$116,925
General Service > 50 kW	7,261,045	6,219,844	7,016,243	7,336,766	7,560,555	$8,501,101
General Service > 1,000 kW	1,357,198	1,266,675	1,340,917	1,308,203	1,287,656	$1,524,423
Embedded Distributor	-	-	-	-	58,833	$176,026
Sentinel Lighting	17,809	6,915	14,921	19,671	22,826	$20,397
Street Lighting	738,744	488,842	904,731	1,204,700	1,307,271	$1,035,894
Total	**$31,136,649**	**$29,806,975**	**$32,085,187**	**$33,510,199**	**$35,767,833**	**$36,880,386**

Variance Analysis

Comparison of 2010 Actual to 2010 Board Approved

As shown in Table 3-29, Oakville Hydro's 2010 actual revenues were $1,329,674 or 4.3% lower than 2010 Board approved distribution revenue despite the fact that actual kWh were higher than forecast. This is partially attributable to the implementation date of May 1, 2010 for Oakville Hydro's approved rates. While the Board approved an increase in revenue of $2,344,060 the implementation date of May 1, 2010 resulted in two thirds of the revenue reflected in the calendar year of 2010, resulting in a revenue shortfall of $781,353. The remaining shortfall of $548,321 is attributed to a reduction in revenue as a result of the economic recession and lower than estimated number of customers. Although Oakville Hydro factored the known impacts of plant relocations and closures into it 2010 load forecast, distribution revenues for the General Service < 50 kW rate classification were 8.3% lower than forecast, for the General Service > 50 kW rate classification distribution revenues were 14.3% lower than forecast and for the General Service > 1,000 kW classification distribution revenues 6.7% lower than forecast. These reductions were offset by higher than forecast revenues for the residential rate class. The impact of the economic recession was also reported by the Town of Oakville in its Economic Development Report. The report stated that, while the Town of Oakville had experienced positive economic growth, its manufacturing sector was less responsive to economic recovery and the Town was impacted by the consolidation of manufacturing plants, relocations and closures[8].

Table 3-29: Distribution Revenue Variance 2010 Board Approved vs. 2010 Actual

Rate Classification	2010 Actual vs 2010 Approved Variance	Variance (%)
Residential	$ 420,388	2.4%
General Service < 50 kW	(367,727)	-8.3%
Unmetered	10,185	7.5%
General Service > 50 kW	(1,041,201)	-14.3%
General Service > 1,000 kW	(90,523)	-6.7%
Embedded Distributor	-	-
Sentinel Lighting	(10,894)	-61.2%
Street Lighting	(249,902)	-33.8%
Total	**$ (1,329,674)**	**-4.3%**

Comparison of 2011 Actual to 2010 Actual

Oakville Hydro's 2011 actual revenues were $2,278,212 or 7.6% higher than 2010 actual revenues. Of this amount, $781,353 is attributable to the impact of a full year of 2010 Board Approved rates. An additional $997,884 is attributable to Oakville Hydro's 2011 IRM. The IRM application included a mechanistic adjustment to its rates, an amount for shared tax savings adjustment and an Incremental Capital Claim. The combined distribution revenue impact of the approval of Oakville Hydro's 2011 IRM application equated to an increase in revenue for the period May 1, 2011 to December 31, 2011. The remaining variance of $498,974 can be attributed to an increase in revenue primarily from the General Service classifications indicating further recovery from the economic recession in part offsetting the slower than anticipated recovery of 2010.

[8] Town of Oakville, 2010 Economic Development Report, page 1.

Table 3-30: Distribution Revenue Variance 2010 Actual vs. 2011 Actual

Rate Classification	2011 vs 2010 Actual Variance	Variance (%)
Residential	$ 647,068	3.7%
General Service < 50 kW	350,145	8.6%
Unmetered	(13,537)	-9.2%
General Service > 50 kW	796,399	12.8%
General Service > 1,000 kW	74,242	5.9%
Embedded Distributor	-	-
Sentinel Lighting	8,006	115.8%
Street Lighting	415,889	85.1%
Total	**$ 2,278,212**	**7.6%**

Comparison of 2012 Actual to 2011 Actual

Oakville Hydro's 2012 actual revenues were $1,425,012 or 4.4% higher than 2011 actual revenues. Of this amount, $606,283 is attributable to the impact of a full year of recovery of the approved revenue requirement for Oakville Hydro's 2011 Incremental Capital claim. In 2012, Oakville Hydro also filed a standalone application for the recovery of costs related to smart meter deployment which resulted in an increase of revenues of $831,651 from May 1, 2011 to December 31, 2011. These increases were offset by Oakville Hydro's IRM application which included a mechanistic adjustment to its rates and an amount for shared tax savings adjustment which resulted in a reduction in distribution revenue of $168,807. The remaining variance of $155,885 is less than one per cent and can be attributed to growth.

Table 3-31: Distribution Revenue Variance 2011 Actual vs. 2012 Actual

Rate Classification	2012 vs 2011 Actual Variance	Variance (%)
Residential	$ 757,097	4.2%
General Service < 50 kW	71,892	1.6%
Unmetered	3,495	2.6%
General Service > 50 kW	320,523	4.6%
General Service > 1,000 kW	(32,714)	-2.4%
Embedded Distributor	-	-
Sentinel Lighting	4,750	31.8%
Street Lighting	299,969	33.2%
Total	**$ 1,425,012**	**4.4%**

Comparison of 2013 Bridge Year to 2012 Actual

Oakville Hydro's 2013 revenues are forecasted to be $1,694,321 or 5.1% higher than 2012 actual revenues. Of this amount, $1,663,302 is attributable to the impact of a full year of recovery of the approved revenue requirement for Oakville Hydro's 2012 approved SMIRR. In 2013 Oakville Hydro filed an IRM application which included a mechanistic adjustment to its rates including an amount for shared tax savings adjustment. Oakville Hydro's IRM resulted in a reduction in distribution revenue of $133,888. The remaining variance of $164,906 is less than one per cent and can be attributed to growth.

Table 3-32: Distribution Revenue Variance 2012 Actual vs. 2013 Bridge Year

Rate Classification	2013 vs 2012 Actual Variance	Variance (%)
Residential	$ 1,554,775	8.2%
General Service < 50 kW	331,910	7.4%
Unmetered	3,149	2.3%
General Service > 50 kW	223,789	3.1%
General Service > 1,000 kW	(20,547)	-1.6%
Embedded Distributor	-	-
Sentinel Lighting	3,155	16.0%
Street Lighting	102,571	8.5%
Total	**$ 2,257,634**	**6.7%**

Weather Normalized Distribution Revenue by Rate Class

Oakville Hydro estimated weather normalized kWh using the regression equation produced by the Load Forecast Model and substituting actual HDD and CDD with weather the normal HDD and CDD values used in the forecast. The difference between the predicted kWh based on the actual HDD and CDD and the predicted kWh based on weather normal HDD and CDD was then added to or subtracted from the actual kWh to derive the weather normal kWh. Oakville Hydro estimated weather normalized kW using the historical relationship between kWh and kW used in the forecast.

As discussed previously, Oakville Hydro was not able to produce a class specific regression model with an acceptable statistical fit. Therefore, Oakville Hydro has allocated the weather normalized consumption to each rate classification using the proportion of billed consumption for each rate classification to total consumption. Weather normalized distribution revenue calculated based on the allocated consumption at existing rates, including the LRAM, SMIRR and ICM rate riders, is provided in Table 3-33.

Table 3-33: Weather Normalized Distribution Revenue at Existing Rates

Rate Class	2010	2011	2012
Residential	$ 18,128,076	$ 18,262,435	$ 19,398,226
GS<50	4,259,929	4,430,853	4,682,227
Unmetered	147,579	135,219	138,893
GS>50	6,338,915	7,189,048	7,421,991
GS >1000	1,308,291	1,344,012	1,334,565
Sentinel Lighting	7,963	16,021	21,371
Street Lighting	469,718	872,894	1,179,699
Total	$ 30,662,483	$ 32,250,483	$ 34,176,971

Weather Normalized Distribution Revenue Variances

Variances between actual distribution revenue by rate classification and normalized distribution revenue by rate classification are provided in Table 3-34, 3-35 and 3-36.

Table 3-34: 2010 Normalized Distribution Revenue by Rate Classification

	2010		
Rate Class	Actual	Normal	Variance
Residential	$ 17,594,797	$ 18,128,076	-3.0%
GS<50	4,083,476	4,259,929	-4.3%
Unmetered	146,426	147,579	-0.8%
GS>50	6,219,844	6,338,915	-1.9%
GS >1000	1,266,675	1,308,291	-3.3%
Sentinel Lighting	6,915	7,963	-15.2%
Street Lighting	488,842	469,718	3.9%
Total	$ 29,806,975	$ 30,660,473	-2.9%

Table 3-35: 2011 Weather Normalized Distribution Revenue by Rate Classification

	2011		
Rate Class	**Actual**	**Normal**	**Variance**
Residential	$ 18,241,865	$ 18,262,435	-0.1%
GS<50	4,433,621	4,430,853	0.1%
Unmetered	132,889	135,219	-1.8%
GS>50	7,016,243	7,189,048	-2.5%
GS >1000	1,340,917	1,344,012	-0.2%
Sentinel Lighting	14,921	16,021	-7.4%
Street Lighting	904,731	872,894	3.5%
Total	$ 32,085,187	$ 32,250,483	-0.5%

Table 3-36: 2012 Weather Normalized Distribution Revenue by Rate Classification

	2012		
Rate Class	**Actual**	**Normal**	**Variance**
Residential	$ 18,998,962	$ 19,398,226	-2.1%
GS<50	4,505,513	4,682,227	-3.9%
Unmetered	136,384	138,893	-1.8%
GS>50	7,336,766	7,421,991	-1.2%
GS >1000	1,308,203	1,334,565	-2.0%
Sentinel Lighting	19,671	21,371	-8.6%
Street Lighting	1,204,700	1,179,699	2.1%
Total	$ 33,510,199	$ 34,176,971	-2.0%

In each of the historical years the actual revenues were lower that the weather normalized revenue

Revenue at Proposed Rates

Revenue at existing and proposed rates is provided in Table 3-37 below.

Table 3-37, Revenue at Existing and Proposed Rates

Rate Class	2014 Revenue at Existing Rates	2014 Proposed Revenue
Residential	$17,835,031	$21,508,431
GS < 50 kW	4,155,428	3,997,189
GS >50 kW	7,054,967	8,501,101
GS >1000 kW	1,265,214	1,524,423
Embedded Distributor	176,352	176,026
Sentinel Lights	21,904	20,397
Street Lighting	858,960	1,035,894
Unmetered and Scattered	131,641	116,925
Total Distribution Revenue	$31,499,496	$36,880,386

Transformer Allowance

Oakville Hydro currently provides a Transformer Ownership Allowance Credit of 0.50 $/kW to General Service > 50 kW customers that own their own on-site transformer facilities. Oakville Hydro is proposing to maintain this rate for the 2014 Test Year for eligible customers in the General Service > 50 kW rate classification.

Other Revenue

Other revenue is defined as sources of utility revenue other than Distribution revenue. This other revenue consists of Board Specific Charges based on standardized rates, interest income and other miscellaneous charges. Other distribution revenue does not include interest on deferral and variance accounts, revenues from non-utility operations and non-utility rental income.

Oakville Hydro is seeking approval to charge the standard specific charge of $30 for service calls during regular hours and $165 after regular hours when providing special or extra services not included in the standard level of service that are provided upon a customer's request.

The other revenues for the 2014 Test Year are forecasted to be $2,035,753. The details of the other revenues are in Appendix 2-H. Overall, other revenue has decreased from 2010 actual based on three main factors:

- Expiration of transitional services and office space rental from a third party
- Expiration of a distribution line rental to Burlington Hydro
- Less cash on hand and lower interest rates

Oakville Hydro has mitigated these decreases in revenues by diligently looking for ways to provide additional services. This is reflected by negotiating in late 2012 leasing of a portion of Oakville Hydro's office space to the Town of Oakville. In addition in 2013, as part of its continued effort to collaborate with other utilities and looking for economies of scale, Oakville Hydro was successful in signing a five-year agreement with Halton Hills Hydro Inc. to provide 24/7 Control Room services to their service area.

Revenue from affiliate transactions is recorded in USofA accounts 4210, 4220, 4390 and 4405 and are identified as "Intercompany" revenue or "Town of Oakville" in Board Appendix 2-H. In addition, revenue from affiliates for shared services and cost allocations are recorded as an offset to Operating, Maintenance and Administration costs in OEB Account 5625. The details are provided in Exhibit 4.

Account Descriptions

Account 4080-1 SSS Administration Charges

Oakville Hydro charges the Board approved rate 0.25 cents per month for customers on standard service supply. The 2014 Test Year estimate is based on the projected number of customers on Standard Supply Service.

Account 4080-2 MicroFIT Charges

Oakville Hydro currently applies a fixed monthly charge of $5.40 per month to the microFIT generator rate class to reflect Board updated province-wide review as per proceeding associated with EB-2009-0326 and EB-2010-0219, and the Board's letter, Update to Fixed Monthly Charge for microFIT Generator Service Classification Board, of September 20, 2012.

Account 4210 Rent from Electric Property

This is a specific charge of $22.35 per pole for access to Oakville Hydro's power poles by other organizations, such as telecommunications and cable companies.

Account 4220 Other Electric revenues

Oakville Hydro has entered into agreements for duct rental, Point of Presence site rental and data centre space charges to a third party. Oakville Hydro had a line rental agreement with Burlington Hydro Inc. ("Burlington Hydro") for two distribution lines (feeder lines) located on Bronte Road to service Burlington Hydro's service territory. This agreement expired on May 31, 2013 and Burlington Hydro has confirmed that at this point it will not be renewing the agreement but it has requested a one year extension of the current agreement. The extension period will end on May 31, 2014. Therefore in the 2014 Test Year, Oakville Hydro has included the normalized revenue amount, namely one fifth of the total revenue from January 1, 2014 to May 31, 2014 because it will only receive this revenue in the Test Year and not beyond this point. There is no opportunity to rent these lines to any other customer.

In the fall of 2013, Oakville Hydro entered into an agreement with Halton Hills Hydro Inc. to provide 24/7 Control Room services for their service area, and revenues related to the agreement are included in revenues. Oakville Hydro’s other electric revenues also include rental revenue from its affiliates for space occupied in its corporate office; this fee is based on the measured square footage occupied by its affiliates.

Account 4225 Late Payment Charges

Oakville Hydro proposes to continue to charge 1.5 per cent per month or 19.56 per cent annually for late payments. This amount is applied to all accounts that are not paid by the due date. Bills are due and payable sixteen days from the mailing date, plus grace days to allow for mailing and payment processing delays. The late payment charges are based on outstanding total bill balance. The 2014 estimate is based on an average of three years and 2% inflation.

Account 4235 Miscellaneous service revenues

Oakville Hydro charges specific charges based on the Board approved its Tariff of Rates and Charges and primarily based on a 2% increase from the last actual results.

Account 4390 Miscellaneous non-operating income

In its 2010 cost of service application, EB-2009-0271, Oakville Hydro identified that it would be providing temporary transitional services to is former affiliate which was sold in Jan 2010 to Rogers Communications Inc., for occupied space, finance, accounts payable and purchasing functions. These services were provided by Oakville Hydro beginning in 2010 and were terminated by January 2012. In late 2012, Oakville Hydro leased a portion of its office space to the Town of Oakville.

Miscellaneous non-operating income also includes the proceeds on sale of material or capital assets (e.g. copper, metals, etc.), recovery of labour, material and vehicle costs for chargeable events that affect the Oakville Hydro distribution system such as damage to poles, transformers or overhead lines (e.g. damage to hydro poles as a result of vehicle accidents), damage to cables through digging, and downed lines as a result of damage caused by tree removal.

Account 4405- Interest Income

Interest income includes monthly interest earned in the bank account as well as interest earned on any temporary intercompany loans to affiliates. Based on Oakville Hydro's negative cash position in May 2012 affiliates no longer borrow from Oakville Hydro and make other arrangements for financing. Oakville Hydro has budgeted an interest rate of 1.275% on current bank accounts.

Year over Year Variance Analysis of Other Revenues:

The following analysis is for account variances that exceed the materiality threshold of $180,000.

2010 Actual vs. 2010 Board-Approved

Account 4390-Miscellaneous Non-Operating Income:

Miscellaneous non-operating income increased by $413,569 as compared to the 2010 Board Approved amount due to:

- The temporary transitional services that Oakville Hydro provided to Rogers Communications, who purchased affiliate Blink Communications on January 29, 2010, resulted in an increase of $255,938. These temporary transitional services were based on an agreement with Rogers Communications. The services included the temporary use of the office space, financial services, mailroom services and warehouse services.

- Other miscellaneous income of $157,631 included recovery of costs of defective meters and the gain on stale-dated cheques.

2010 Actual vs. 2011 Actual

Account 4375-Revenue from Non-Utility Operations:

This account decreased by $489,428 in 2011 from the 2010 Actual due to the pre-2011 OPA incentives received for CDM activities and the one-time recording of the late payment penalty.

2011 Actual vs. 2012 Actual

Account 4375-Revenue from Non-Utility Operations:

This account increased by $180,431 in 2012 for the one-time recovery for Oakville Hydro's assistance in the Long Island storm.

Account 4390-Miscellaneous Non-Operating Income:

Miscellaneous non-operating income decreased by $362,744 as compared to the 2011 actual amount due to:

- The termination of all temporary transitional services that Oakville Hydro provided to Rogers Communications. Rogers vacated the space in January 2012.

2012 Actual vs. 2013 Bridge

Account 4375-Revenue from Non-Utility Operations:

This account decreased by $199,776 in the 2013 Bridge Year as in 2012 Oakville Hydro recovered costs for Oakville Hydro's crews' assistance in the Long Island storm.

2013 Bridge vs. 2014 Test

The variance between the 2013 Bridge Year and the 2014 Test Year other revenue is not material.

Other operating revenue for the historical years 2010, 2011, and 2012 and forecasted other operating revenue for the 2013 Bridge Year and the 2014 Test Year are summarized in the Board's appendix 2-H, Other Operating Revenues below.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual[2]	Bridge Year[3]	Test Year
					2013	2014
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
4080-2	SSS Admin Charge	$170,451	$174,932	$185,838	$184,600	$196,383
	MicroFIT charges	149	1,042	1,719	0	0
4210	Rent from Electric Property	129,628	142,904	144,365	137,000	139,700
4220	Other Electric Revenues	583,421	515,797	515,844	556,699	527,650
4225	Late Payment Charges	288,100	314,134	335,244	321,726	325,000
4235	Miscellaneous Service Revenues From Non-Utility Operations	300,454	278,387	314,040	272,600	282,200
4385	Non-Utility Rental Income	9,510	9,168	9,202	9,500	0
4375/4080	Revenues from non utility operations	508,773	19,345	199,776	0	0
4390	Miscellaneous Non-Operating Incor	922,739	767,618	404,874	355,794	356,820
4398	Foreign Exchange Gains and Losses, Including Amortization	83,547	17,522	3,781	1,236	4,000
4405	Interest and Dividend Income	359,701	285,041	327,259	216,568	204,000
Specific Service Charges		300,454	278,387	314,040	272,600	282,200
Late Payment Charges		288,100	314,134	335,244	321,726	325,000
Other Operating Revenues		883,648	834,675	847,766	878,299	863,733
Other Income or Deductions		1,884,270	1,098,694	944,892	583,097	564,820
Total		$ 3,356,472	$ 2,525,890	$ 2,441,942	$ 2,055,722	$ 2,035,753

Account 4210-Rent from Electric Property

	2010 Actual	2011 Actual	2012Actual²	Bridge Year	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Pole Rental - Rogers/Bell/Other	$122,457	$142,904	$144,365	$137,000	$139,700
Pole Rental- Blink (Intercompany)	7,171	0	0	0	0
Total	**$129,628**	**$142,904**	**$144,365**	**$137,000**	**$139,700**

Account 4220-Other Electric Revenues

	2010 Actual	2011 Actual	2012Actual²	Bridge Year	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Point of Presence Site Rental-Rogers	$27,900	$27,900	$27,900	$27,900	$28,500
Data Ctr & Generator - Rogers	113,575	123,900	125,377	125,511	128,000
Duct Rental-Rogers	19,922	21,733	22,720	22,810	23,500
Line Rental - Burlington	156,000	156,000	156,000	156,000	13,000
Other	-1,258	6	32	4,000	0
Intercompany- billing charges/vehicles insurance	85,766	75,058	100,599	75,578	106,750
Intercompany - Occupancy recovery	179,705	111,200	83,216	119,900	127,900
Control Room services -Halton Hills Hydro Inc.	0	0	0	25,000	100,000
Blink - Duct Rental	1,811				
Total	**$583,421**	**$515,797**	**$515,844**	**$556,699**	**$527,650**

Account 4225-Late Payment Charges

	2010 Actual	2011 Actual	2012Actual²	Bridge Year	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
LPC-Energy	$218,019	$232,557	$249,041	$237,447	$240,500
LPC - Water/Sewer	70,081	81,576	86,203	84,279	84,500
Total	**$288,100**	**$314,134**	**$335,244**	**$321,726**	**$325,000**

Account 4235-Miscellaneous Service Revenues From Non-Utility Operations

	2010 Actual	2011 Actual	2012Actual²	Bridge Year	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Temporary Service Charg	$29,249	$25,500	$29,139	$26,600	$31,200
Arrears Certificate Cha	4,997	3,718	4,665	5,500	5,600
Returned Cheque Collect	11,803	8,130	10,180	8,500	8,700
Reconnect Charge	15,075	14,875	14,970	13,500	13,800
Deposit Waiver Fees	10,446	4,339	5,352	4,500	4,600
Other	645	1,710	1,845	1,000	1,000
Occupancy Charge	214,170	207,510	232,680	200,000	204,000
Disconnect Fee	14,070	12,605	15,210	13,000	13,300
Total	**$300,454**	**$278,387**	**$314,040**	**$272,600**	**$282,200**

Account 4375-Revenues from Non-Utility Operations

	2010 Actual	2011 Actual	2012Actual²	Bridge Year	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
CDM revenues Pre-2011 OPA CDM Incentives	$251,201	$19,345	$0	$0	$0
Long Island , New York Storm Assistance	0	0	199,776	0	0
Late payment penalty- one-time	257,572	0	0	0	0
Total	**$508,773**	**$19,345**	**$199,776**	**$0**	**$0**

Account 4385-Non-Utility Rental Income

	2010 Actual	2011 Actual	2012Actual²	Bridge Year	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Sentinel Light Rental	$9,510	$9,168	$9,202	$9,500	$0
Total	**$9,510**	**$9,168**	**$9,202**	**$9,500**	**$0**

Account 4390-Miscellaneous Non-Operating Income

	2010 Actual	2011 Actual	2012Actual²	Bridge Year	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Rogers- Temporary Transitional Services	$430,938	$318,222	$26,191	$0	$0
Office Space rental-Town of Oakville	0	0	36,707	146,829	146,820
Billable Sevices	121,424	184,720	156,802	152,554	153,000
Benefit Refund Deposit Account	0	111,455	127,779	0	0
Cash Discount on Purchases	16,201	19,796	7,226	4,996	6,000
SR & ED Credits	99,110	0	0	0	0
Miscellaneous Income	131,349	-299	-79,355	6,000	6,000
Miscellaneous one time- (defect meter recovery/late paymts charge/staledated cheques)	69,093	31,097	54,603	0	0
Proceeds on Sale of Materials	54,623	71,627	58,703	45,415	45,000
Proceeds on Sale of Capital Assets	0	31,000	16,218	0	0
Total	**$922,739**	**$767,618**	**$404,874**	**$355,794**	**$356,820**

Account 4398-Foreign Exchange Gains and Losses, Including Amortization

	2010 Actual	2011 Actual	2012Actual²	Bridge Year	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Exchange Gain or Loss	$83,547	$17,522	$3,781	$1,236	$4,000
Total	**$83,547**	**$17,522**	**$3,781**	**$1,236**	**$4,000**

Account 4405 - Interest and Dividend Income

	2010 Actual	2011 Actual	2012Actual²	Bridge Year	Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Interest Income	$95,156	$5,842	$81,725	$216,568	$204,000
Interest earned from affiliates - for notes payable	182,481	104,593	118,303	0	0
Interest earned on deferral and variance accounts	82,065	174,606	127,231	0	0
Total	**$359,701**	**$285,041**	**$327,259**	**$216,568**	**$204,000**

Specific Service Charge

Oakville Hydro is seeking approval to continue the Specific Service Charges and Transformer Allowance approved in the Board Decision and Order in the matter of Oakville Hydro's 2013 Distribution Rates (EB-2012-0154). In addition, Oakville Hydro is seeking approval for the standard specific charge for service calls when providing customer-requested special or extra services not included in a standard level of service. While revenues for these services are not expected to be material, Oakville Hydro believes that the application of a standard charge for service is a better reflection of cost causality.

In accordance with the Filing Requirements, Oakville has provided the calculation of the cost to provide the services. Oakville Hydro has calculated the cost of responding to Customer requested service calls during regular hours to be $28.12 and the cost of responding to customer requested service calls outside of regular hours to be $210.94. The detailed calculations are provided in Table 3-38 and 3-39. However, Oakville Hydro is proposing to charge the standard specific service charge of $30.00 during regular hours and $165.00 outside of regular hours in order to maintain consistency within the Province.

Table 3-38, Customer Requested Service Calls During Regular Hours

	Rate	Hours	OT factor	Calculated Cost
Direct Labour-average rate (Line personel)	$40.18	0.50		$20.09
Direct Labour-overtime				
Payroll Burden 30%	12.05	0.50		6.03
Total Labour Cost				26.12
Vehicle charges	$4.00	0.50		2.00
Total Other				2.00
Calculated Specific Service Charge				$28.12

Table 3-39, Customer Requested Service Calls Outside Regular Hours

	Rate	Hours	OT factor	Calculated Cost
Direct Labour-average rate (Line personel)				
Direct Labour-overtime	$40.18	2.00	$2.00	$160.72
Payroll Burden 30%	12.05	2.00	2.00	48.22
Total Labour Cost				208.94
Vehicle charges	$4.00	0.50		2.00
Total Other				2.00
Calculated Specific Service Charge				$210.94

Charges Included in Oakville Hydro’s Conditions of Service

The charges that are included in Oakville Hydro’s Conditions of Service but do not appear on the Board-approved tariff sheet are included in Account 4390 (Billable Services), in Board Appendix 2-H of this Exhibit.

Appendix A

Milton Hydro Load

MILTON HYDRO DISTRIBUTION INC.
8069 Lawson Road, Milton, Ontario L9T 5C4

July 19, 2013

Dan Steele, P. Eng., M.B.A.
Director, Engineering & Construction
Oakville Hydro Distribution Inc.
P.O. Box 1900
861 Redwood Square,
Oakville, ON L6J 5E3

Milton Hydro Load at Glenorchy MTS

Dan,

As a follow up to our discussion, below is the load profile for the aggregate load Milton Hydro is preparing to transfer to Glenorchy MTS.

Month	Maximum One Hour Demand in kW	Average Demand in kW	L.F.
Jan-14	5700	4100	71.9%
Feb-14	5600	4100	73.2%
Mar-14	5400	3800	70.4%
Apr-14	5000	3600	72.0%
May-14	6300	3400	54.0%
June-14	7800	3800	48.7%
July-14	7900	4800	60.8%
Aug-14	6900	4200	60.9%
Sept-14	6600	3500	53.0%
Oct-14	4800	3300	68.8%
Nov-14	5400	3600	66.7%
Dec-14	5600	4000	71.4%

Should you require any further information don't hesitate to contact me at you convenience.

Regards
Bruno Pereira, P. Eng, MBA
Director of Engineering
Milton Hydro Distribution Inc.
(289) 429-5213
BrunoPereira@MiltonHydro.com