THUNDER BAY HYDRO

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November 8, 2012

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

Dear Ms. Walli:

Re: Thunder Bay Hydro Electricity Distribution Inc. - 2013 Cost of Service Electricity Distribution Rate Application EB-2012-0167

Thunder Bay Hydro Electricity Distribution Inc. ("Thunder Bay Hydro") is applying for authorization to adjust its current electricity distribution rates in accordance with its 2013 Cost of Service Electricity Distribution Rate Application.

In support of its Application Thunder Bay Hydro utilized the following excel files to calculate the requested adjusted rates:

- 2013 Revenue Requirement Workform
- 2013 Load Forecast
- 2013 Filing Requirements Chapter 2 Appendices
- 2013 Income Tax PILs Workform
- 2013 RSTR Model Workform
- 2013 EDDVAR Continuity Schedule
- 2013 Cost Allocation Model
- 2011 OPA Final Evaluation Report
- Green Energy Act Funding Adder Workform

Please find enclosed two hard copies of Thunder Bay Hydro's 2013 Cost of Service Electricity Distribution Rate Application. An electronic version of this application has been submitted through the e-Filing Services and emailed to the Board Secretary.

If you require any further information, please contact the undersigned at (807) 343-1118.

Yours truly,

Jenni Pajala, for

Cindy Speziale, CA
Vice President, Finance

THUNDER BAY HYDRO ELECTRICITY DISTRUBUTION INC.

APPLICATION FOR APPROVAL OF ELECTRICITY DISTRIBUTION RATES EFFECTIVE MAY 1, 2013

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ABBREVIATIONS

Accounting Procedures Handbook (APH)

Advanced Metering Infrastructure (AMI)

Affiliate Relationships Code for Electricity Transmitters and Distributors (ARC)

Allowance for Funds Used During Construction (AFUDC)

Alternating Current (AC)

Asset Management Plan (AMP)

Asset Retirement Obligation (ARO)

Bankers' Acceptance (BA)

Base Revenue Requirement (BRR)

Canadian Electricity Association (CEA)

Canadian Generally Accepted Accounting Principles (CGAAP)

Canadian Institute of Charted Accountants (CICA)

Canadian Pension Plan (CPP)

Canadian Radio-Television and Telecommunications Commission (CRTC)

Canadian Standards Association (CSA)

Canadian Accounting Standards Board (AcSB)

Capital Cost Allowance (CCA)

Capacity Allocation Exempt (CAE)

Capacity Allocation Required Applications (CAR)

Conservation and Demand Management (CDM)

Construction-Work-in-Progress (CWIP)

Consumer Price Index (CPI)

Corporation of the City of Thunder Bay (City of Thunder Bay)

Cost of Service (COS)

Cross Link Poly ethylene (XLPE)

Cumulative Eligible Capital (CEC)

Customer Average Interruption Duration Index (CAIDI)

Customer Information System (CIS)

Deferral and Variance Accounts (DVAs)

Direct Current (DC)

Dissolved Gas Analysis (DGA)

Distribution Availability Test (DAT)

Distribution Service Code (DSC)

Distribution Stations (DS)

Economic Connection Test (ECT)

Electrical & Utilities Safety Association (EUSA)

Electrical Safety Authority (ESA)

Electricity Distribution Rate (EDR)

Electricity Distributors Association (EDA)

Electronic Business Transactions (EBT)

Eligible Capital Expenditure (ECE)

Enterprise Resource Planning (ERP)

Ethylene Propylene (EPR)

Fair Market Value (FMV)

Feed-In Tariff (Fit)

First-In-First-Out ("FIFO")

Fit Application Management Environment (FAME)

Fort William Transformer Station (FWTS)

Full Time Equivalent (FTE)

General Accepted Accounting Principles (GAAP)

General Service (GS)

Geographic Information System (GIS)

Green Energy Act (GEA)

Gross Domestic Product (GDP)

Harmonized Sales Tax (HST)

Hourly Ontario Energy Price (HOEP)

Incentive Regulation Mechanism (IRM)

Independent Electricity System Operator (the IESO)

Information Service Division (ISD)

Information System Department (ISD)

Information Technology (IT)

Input Tax Credit (ITC)

Integrated Power System Plan (IPSP)

International Brotherhood of Electrical Workers (IBEW)

International Financial Reporting Standards (IFRS)

International Organization for Standardization (ISO)

Kilo Volt Amperes (kVa)

Kilowatt (kW)

Kilowatt hours (kWhs)

Large Corporation Tax (LCT)

Local Area Network (LAN)

Local Distribution Company (LDC)

Long Term (LT)

Long Term Disability (LTD)

Lost Revenue Adjustment Mechanism (LRAM)

Low Income Energy Assistance Program (LEAP)

Low Voltage (LV)

Mapleward Renewable Generation Station (MRGS)

Market Based Rate of Return (MBRR)

Meter Data Management/Repository (MDM/R)

Meter Data Management for Interval Meter Customers (MV90)

Meter Service Provider (MSP)

Metering and Electricity Revenue (MER)

Ministry of Labour (MOL)

Ministry of Transportation (MTO)

Ministry of Environment and Energy (MOEE)

Modified Canadian Generally Accepted Accounting Principles (MCGAAP)

Modified International Financial Reporting Standards (MIFRS)

Momentary Average Interruption Frequency Index (MAIDI)

Municipal Electric Association Reciprocal Insurance Exchange (MEARIE)

Net Book Value (NBV)

North American Occupational Safety and Health Week (NAOSH)

Occupational Health, Safety and Environment (OH&S)

Occupational Health and Safety Assessment Series (OHSAS)

Ontario Energy Association (OEA)

Ontario Energy Board (OEB)

Ontario Municipal Employees Retirement System (OMERS)

Ontario Municipal Employees Retirement System Primary Pension Plan (OMERS Plan)

Ontario Municipal Employees Retirement System Supplemental Plan for Police, Firefighters and Paramedics (Supplemental Plan)

Ontario Value Added Tax (OVAT)

Ontario Power Authority (OPA)

Ontario Power Generation (OPG)

Ontario Price Credit (OPC)

Ontario Uniform Transmission Rates (UTRs)

Operational Data Storage (ODS)

Operations and Maintenance (O&M)

Operations, Maintenance and Administration (OM&A)

Outage Management System (OMS)

Overhead (OH)

Paid-up Capital (PUC)

Paper Insulated Lead Covered (PILC)

Parts Per Million (ppm)

Parts Per Billion (ppb)

Payments in Lieu of Taxes (PILs)

Peak Load Carrying Capability (PLCC)

Personal Computer (PC)

Polychlorinated Biphenyls (PCBs)

Post Retirement Employee Benefits (PREB)

Power Line Technician (PLT)

Production Action Reports (PARs)

Provincial Sales Tax (PST)

Property Plant & Equipment (PP&E)

Public Service Works on Highways Act (PSWHA)

Quality Assurance (QA)

Quality Control (QC)

Regulated Price Plan (RPP)

Remote Terminal Unit (RTU)

Reliability Centered Maintenance (RCM)

Reporting and Record Keeping Requirements (RRR)

Retail Cost Variance Account (RCVA)

Retail Settlement Code (RSC)

Retail Settlement Variance Account (RSVA)

Retail Transmission Service Rates (RTSRs)

Radical Boom Derrick (RBD)

Renewable Enabling Improvements (REIs)

Renewable Energy Standard Offer Program (RESOP)

Request for Proposal (RFP)

Return on Equity (ROE)

Second Generation Incentive Regulation Mechanism (2GIRM)

Service Agreements (SAs)

Shared Savings Mechanism (SSM)

Smart Meters (SM)

Smart Meter Disposition Rate Rider (SMDR)

Smart Meter Incremental Rate Rider (SMIRR)

Smart Meter Initiative (SMI)

Special Purpose Charge (SPC)

Sponsors Corporation (SC)

Stranded Asset Rate Rider (SMRR)

Supervisory Control and Data Acquisition (SCADA)

System Average interruption Duration Index (SAIDI)

System Average Interruption Frequency Index (SAIFI)

System of Accounts (SOA)

Third Generation Incentive Regulation Mechanism (3GIRM)

Thunder Bay Hydro Corporation (TBHC)

Thunder Bay Hydro Electricity Distribution Inc. (TBHEDI)

Thunder Bay Renewable Power Incorporated (TBRPI)

Thunder Bay Utility Services Inc. (TBUSI)

Time Current Characteristics (TCC)

Time-of-Use (TOU)

Total Loss Factor (TLF)

Transmission Availability Test (TAT)

Transformer Ownership Credit (TOC)

Transformer Stations (TS)

Tree Retardant Cross Linked Polyethylene Insulated Cables (TBRXLPE)

Typical Useful Life (TUL)

Undepreciated Capital Cost (UCC)

Underground (U/G)

Uniform System of Accounts (USofA)

Unmetered Scattered Load (USL)

Utility Work Protection Code (UWPC)

Validating, Editing and Estimating (VEE)

Vice president (VP)

Vulnerable Energy Consumers Coalition (VECC)

Wide Area Network (WAN)

Working Capital Allowance (WCA)

Workplace Safety and Insurance Board (WSIB)

Year’s Maximum Pensionable Earnings (YMPE)

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

AND IN THE MATTER OF an Application by THUNDER BAY 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, 2013.

Title of Proceeding: An application by THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC. for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2013.

Applicant's Name: THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

Applicant's Address: 34 Cumberland St. N, Thunder Bay, Ontario

Applicant's Contacts: Robert Mace, President
Telephone: (807) 343-1122
Fax: (807) 343-0230
E-mail: rmace@tbhydro.on.ca

APPLICATION

Introduction

The Applicant is Thunder Bay Hydro Electricity Distribution Inc. ("Thunder Bay Hydro"). The Applicant is a corporation incorporated pursuant to the Ontario Business Corporations Act with its head office in the City of Thunder Bay, ON. The Applicant carries on the business of distributing electricity within the City of Thunder Bay.

The Applicant hereby applies to the Ontario Energy Board (the "OEB") pursuant to Section 78 of the Ontario Energy Board Act, 1998 ("the OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2013. A list of requested approvals is set out below.

In the event that the OEB is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2013, the Applicant requests that the OEB issue an interim Order approving the current distribution rates and other charges effective May 1, 2013, which may be subject to adjustment based on its final Decision and Order.

Except where specifically identified in the Application, the Applicant followed the OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, update issued June 28, 2012 (the "Filing Requirements") in order to prepare this application.

Thunder Bay Hydro's Vice President of Finance certifies that the evidence filed in the application is accurate to the best of her knowledge and belief.

Publication of Notice

The Applicant proposes to publish the notice through the local Chronicle Journal newspaper which is a paid publication with a daily readership and circulation of approximately 25,000.

Proposed Distribution Rates and Other Charges

The Schedule of Proposed Tariff of Rates and Charges in this Application is set out in Exhibit 8, Appendix 8-B. The material being filed in support of this Application sets out Thunder Bay Hydro's approach to its distribution rates and charges.

The Proposed Distribution Rates and Other Charges are Just and Reasonable

The Applicant submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:

The proposed rates, as set out in Exhibit 8, Appendix 8-B, for the distribution of electricity have been prepared in accordance with the Filing Requirements and reflect traditional rate making and cost of service principles;

The proposed and adjusted rates are necessary to ensure Thunder Bay Hydro has sufficient funds to meet its capital expenditure obligations, fund OM&A expenses, and provide for a reasonable Market Based Rate of Return ("MBRR") and Payments in Lieu of Taxes ("PILS");

There are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant or the implementation of any other mitigation measures.

The other specific service charges proposed by the Applicant are the same as those previously approved by the OEB; and

Such other grounds as may be set out in the material accompanying this Application Summary.

Relief Sought

The Applicant applies for an Order or Orders approving the proposed distribution rates and charges set out in Exhibit 8 to this Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2013.

The Applicant seeks approval of its Basic Green Energy Plan as part of this Application in accordance with the Deemed Conditions of License as reported by the OEB in its Distribution System Planning Guidelines G-2009-0087, issued June 16, 2009. The Applicants Basic Green Energy Plan has been prepared in accordance with the OEB's Filing Requirements as reported

in EB-2009-0397 – Distribution System Plans under the Green Energy Act revised on May 17, 2012.

The CGAAP budget was approved by the Thunder Bay Hydro's Board of Directors September 20, 2012.

Form of Hearing Requested

The Applicant requests that this Application be disposed of by way of a written hearing.

DATED at Thunder Bay, Ontario, this 8th day of November, 2012.

All of which is respectfully submitted,

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

Cindy Speziale, Vice President, Finance

CONTACT INFORMATION

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

PRESIDENT:	Robert Mace Telephone: (807) 343-1122 Fax: (807) 343-0230 E-mail: rmace@tbhydro.on.ca
VICE PRESIDENT, FINANCE:	Cindy Speziale, CA Telephone: (807) 343-1118 Fax: (807) 343-1009 E-mail: cspeziale@tbhydro.on.ca

SPECIFIC APPROVALS REQUESTED

In this proceeding, Thunder Bay Hydro is requesting the following approvals:

- Approval to charge rates effective May 1, 2013 to recover a service revenue requirement of $21,652,791 which includes a revenue deficiency of $1,559,334 as set out in Exhibit 6, Schedule 1, Tab 1; the schedule of proposed rates is set out in Exhibit 8, Appendix 8-B;
- Approval of the proposed loss factor as set out in Exhibit 8, Tab 1, Schedule 3;
- Approval to charge a Retail Transmission Network Service rate and a Retail Transmission Connection Rate as proposed and described in Exhibit 8, Tab 1, Schedule 2;
- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of Thunder Bay Hydro's 2012 Distribution Rates (EB-2011-0197);
- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of Thunder Bay Hydro's 2012 Distribution Rates (EB-2011-0197);
- Approval to dispose of the following Deferral and Variance Account balances as at December 31 2011 plus forecasted interest over a one year period using the method of recovery described in Exhibit 9, Tab 2, Schedule 4:

  1508 Other Regulatory Assets-OMERS

  1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

  1508 Other Regulatory Assets – Sub –account IFRS Cost Deferral

  1518 Retail Cost Variance Account

  1548 Retail Cost Variance Account (STR)

  1590 Recovery of Regulatory Asset Balances

1580 RSVA - Wholesale Market Service Charges

1584 RSVA - Transmission Network

1586 RSVA - Transmission Connection

1588 RSVA - Power

1588 RSVA – Power Sub Account Global Adjustment

1592 PILS and Tax Variances for 2006 and Subsequent Years – Sub-account HST

1595 Disposition and Recovery/Refund of Regulatory Balances (2008)

1595 Disposition and Recovery/Refund of Regulatory Balances (2009)

- Approval to establish a renewable generation funding adder to support renewable enabling improvements within Thunder Bay Hydro's Green Energy Act Plan.

- Approval to recover amounts related to LRAM/SSM amounts related to activities in 2011 over a one year period, using the method of recovery described in Exhibit 9, Tab 5, Schedule 1;

- In Thunder Bay Hydro's 2010 IRM Decision (EB-2009-0250) the Board directed the utility to record in account 1592 the incremental Input Tax Credit (ITC) it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Thunder Bay Hydro has complied with this directive and has been recording these amounts as of July 1, 2010. The application Thunder Bay Hydro is currently submitting is based on budgeted information net of any HST ITCs Thunder Bay Hydro will receive. As a result, Thunder Bay Hydro requests approval to discontinue recording these variances as of May 1, 2013.

- Approval to dispose of Thunder Bay Hydro's stranded meter costs based on the estimated NBV of its stranded assets as at December 31, 2012 described in Exhibit 9, Tab 3, Schedule 1.

- Approval of variance and deferral accounts to track amounts that arise due to the change in capitalization policy in anticipation of changes required in accounting principles due to IFRS, notably the de-recognition of assets and post retirement employee benefits. See Exhibit 9, Tab 2, Schedule 5.

PROPOSED ISSUES LIST

The Applicant would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2013 Test Year may constitute issues in this Application:

GENERAL (Exhibit 1)

- Are the Applicant's overall economic and business planning assumptions for the Test Year appropriate?
- Is the proposed revenue requirement appropriate?

RATE BASE (Exhibit 2)

- Is the Applicant's asset planning assumptions (e.g. asset condition, economic conditions, etc.) appropriate?
- Is service quality, based on the Board specified performance indicators, acceptable?
- Is the Applicant's capitalization and depreciation policy appropriate?
- Are the capital expenditures appropriate?
- Are the in-service dates accurate for projects closed prior to the Test Year and are they appropriate for proposed projects?
- Is the working capital allowance for the test year appropriate?
- Is the proposed rate base for the test year appropriate?
- Is the accounting for smart meters in rate base appropriate?
- Is the accounting for stranded meters appropriate?
- Is the basic Green Energy Plan appropriate?

LOADS, CUSTOMERS - THROUGHPUT REVENUE (Exhibit 3)

- Is the load forecast methodology including weather normalization appropriate?

- Are the proposed customers/connections and load forecasts (both kWh and kW) for the test year appropriate?
- Is CDM appropriately reflected in the load forecast?
- Are the proposed revenue offsets appropriate?

<u>OPERATING COSTS (Exhibit 4)</u>

- Is the overall OM&A forecast for the test year appropriate?
- Are the methodologies used to allocate shared services and other costs appropriate?
- Is the proposed level of depreciation/amortization expense for the test year appropriate?
- Are the 2012 compensation costs and employee levels appropriate?
- Is the test year forecast of PILs appropriate?

<u>COST OF CAPITAL AND RATE OF RETURN (Exhibit 5)</u>

- Is the proposed capital structure appropriate?
- Is the cost of debt appropriate?
- Is the proposed return on equity appropriate?

<u>CALCULATION OF REVENUE DEFICIENCY OR SURPLUS (Exhibit 6)</u>

- Is the calculation of Revenue Deficiency accurate?

<u>COST ALLOCATION (Exhibit 7)</u>

- Is the Applicant's cost allocation appropriate?
- Are the proposed revenue-to-cost ratios appropriate?

RATE DESIGN (Exhibit 8)

- Are the customer charges and the fixed-variable splits for each class appropriate?
- Are the proposed Retail Transmission Service Rates appropriate?
- Are the proposed loss factors appropriate?
- Is the Applicant's proposed Tariff of Rates and Charges appropriate?

DEFERRAL AND VARIANCE ACCOUNTS (Exhibit 9)

- Are the account balances, cost allocation methodology and disposition plan appropriate?
- Is the Applicant's proposal to dispose of the Capital Stranded Meter Assets appropriate?
- Is the Applicant's proposal to claim LRAM for 2011 OPA CDM appropriate?
- Is the Applicant's proposal to request variance and deferral accounts to track amounts that arise due to the change in capitalization policy in anticipation of changes required in accounting principles due to IFRS, notably the de-recognition of assets and post retirement employee benefits appropriate?

1 **PROCEDURAL ORDERS/MOTIONS/NOTICES**

On January 26, 2012 the Board issued its list of distributors that it anticipates will be filing a Cost of Service Applications for 2013. Thunder Bay Hydro was included on that list.

ACCOUNTING ORDERS REQUESTED

Thunder Bay Hydro is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

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

DISTRIBUTION SERVICE TERRITORY AND DISTRIBUTION SYSTEM

Description of Distributor:

COMMUNITY SERVED:	City of Thunder Bay
TOTAL SERVICE AREA:	381 sq. km
RURAL SERVICE AREA:	259 sq. km
DISTRIBUTION TYPE:	Electricity distribution
SERVICE AREA POPULATION:	110,049
MUNICIPAL POPULATION:	121,596
BOUNDRIES:	Hydro One

A schematic diagram of Thunder Bay Hydro's distribution system and service Territory accompanies this Schedule as Appendix 1-A.

Thunder Bay Hydro notes that it has not had any transmission assets (>50 kV) deemed previously by the Board as distribution assets and there are not any such assets that the Applicant is seeking Board approval to be deemed as distribution assets in the present application.

LIST OF NEIGHBOURING UTILITIES

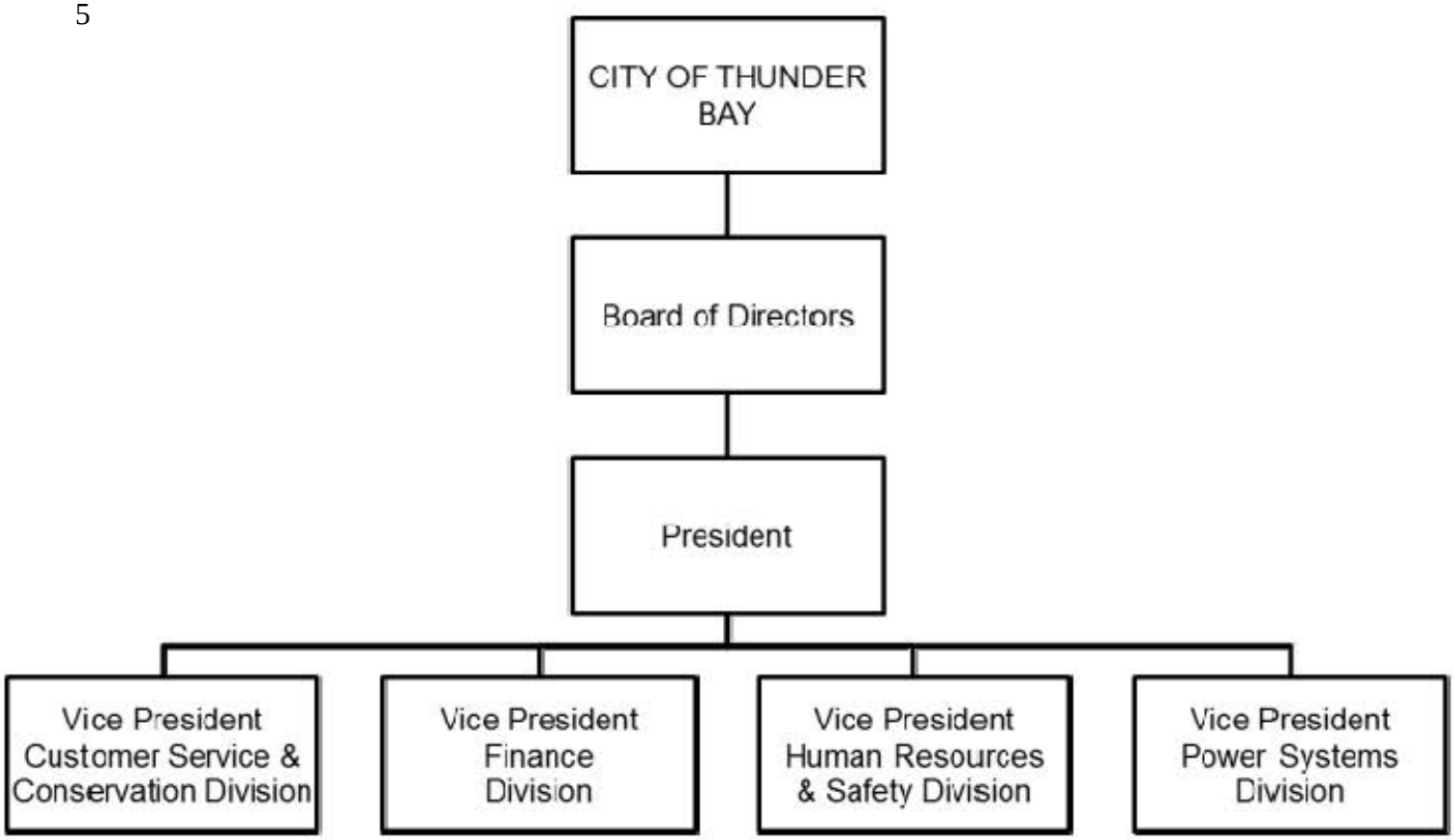
Thunder Bay Hydro is bounded by Hydro One on all service territory boundaries.

EXPLANATION OF HOST AND EMBEDDED UTILITIES

Thunder Bay Hydro confirms that it is not a host utility or an embedded distributor and no partially embedded distributor status exists.

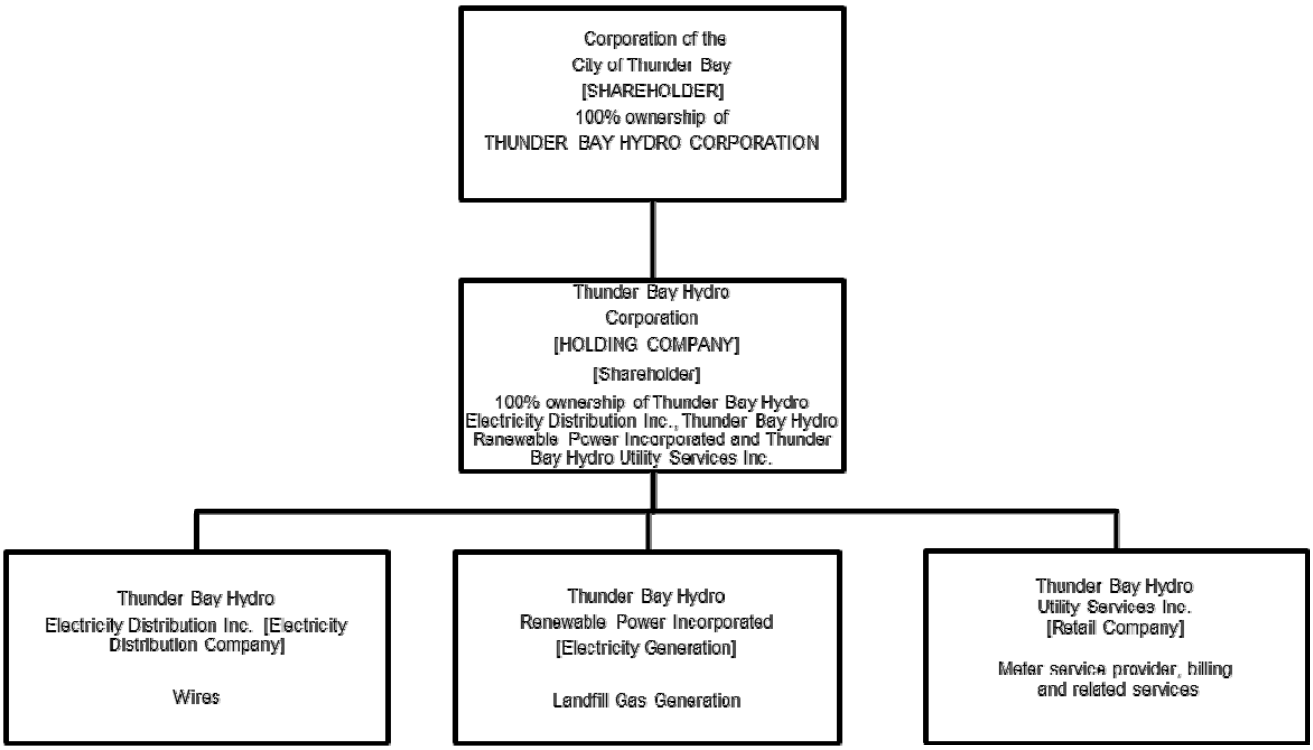
UTILITY ORGANIZATIONAL STRUCTURE

Thunder Bay Hydro's organizational charts showing the main units and executive positions within the utility can be seen below:



CORPORATE ENTITIES RELATIONSHIP CHART

Thunder Bay Hydro is 100% owned by its parent company Thunder Bay Hydro Corporation (TBHC) which is 100% owned by the Corporation of the City of Thunder Bay. A chart illustrating Thunder Bay Hydro's corporate entities relationships is provided below.



SHARED SERVICES

Thunder Bay Hydro Corporation is the parent company for three affiliates; Thunder Bay Renewable Power Incorporated (TBRPI), a generation company; Thunder Bay Hydro Electricity Distribution Inc., (Thunder Bay Hydro) the Distribution Company; and Thunder Bay Hydro Utility Services Inc. (TBHUSI), a back office services company. Competitive meter service provider (MSP) services are also provided within TBHUSI to northern commercial and industrial customers. Thunder Bay Hydro provides certain services to its various affiliates. Thunder Bay

Hydro recovers revenues from TBHUSI and TBRPI in respect of the services it provides, and these revenues are as per the Services Agreements in Exhibit 4, Appendix 4-A.

Related party transactions with the City of Thunder Bay include Thunder Bay Hydro's payment of property taxes, rent, water and sewer charges, telephone charges and the City of Thunder Bay's payment to Thunder Bay Hydro for electricity bills and contributions towards capital. The foregoing involves non-discretionary transactions. Thunder Bay Hydro does not have a Services Agreement with the City of Thunder Bay.

Services Provided By Thunder Bay Hydro to TBHUSI

TBHUSI is a back office services company that provides wholesale settlement, EBT, meter reading, MV90, customer information system, bill production and mailing, after hours system control, related ISD services and conservation programming exclusively to the smaller LDC's in Northwestern Ontario. Also, Thunder Bay Hydro offers AMI services to the districts which includes synchronization of the meter data across the AMI, ODS and MDM/R systems, business process development and management, licensing and hardware and software support. The services are provided to regional LDC's only, and are not marketed or promoted to a larger group. The arrangements with the regional LDC's allows for overall efficiencies to be gained by sharing of expertise and excess capacity. Essentially, the smaller utilities contracts with TBHUSI for the primary reason of being remotely hosted on Thunder Bay Hydro's computer systems for their use of hardware and software for Customer Information Systems, financials, remote meter reading, etc.

For the most part, the Northern Ontario utilities perform their own work with their own staff on the computer systems through remote access with minimal assistance from Thunder Bay Hydro staff. Thunder Bay Hydro staff monitors the MV90 and wholesale settlement systems to make sure utility meter data passes VEE rules prior to transmission to the billing system. Thunder Bay Hydro staff also process EBT transactions, make billing collection calls, receive after hours outage calls on behalf of and for regional LDCs and provide ISD support related to the information systems being used.

TBHUSI is also registered as a Meter Service Provider with the IESO to provide metering related services to Northwestern Ontario commercial and industrial customers. TBHUSI contracts with Thunder Bay Hydro for staff and equipment to carry out this work. Thunder Bay Hydro bills TBHUSI based on the Service Agreement.

Services Provided By Thunder Bay Hydro to TBRPI

TBRPI is a wholly-owned subsidiary company of TBHC which operates a landfill gas generation plant under a 20-year contract with the OPA effective August, 2010. TBRPI receives services from Thunder Bay Hydro on a fully-allocated basis which is calculated annually and charged on a fixed monthly basis.

Thunder Bay Hydro confirms that in the accounting treatment of its generation operations, it has segregated all of all of these activities from its rate-regulated activities and is in compliant with the Board's *Guidelines: Regulation and Accounting Treatment for Distributor-Owned Generation Facilities G-2009-0300.*

Services Provided By Thunder Bay Hydro to TBHC

TBHC serves as a holding company and has 100% ownership of Thunder Bay Hydro, TBHUSI, and TBRPI. A service agreement has been signed between TBHC and Thunder Bay Hydro in 2012 covering TBHC Board Member remuneration, as set out by the shareholder, paid via Thunder Bay Hydro at cost.

PLANNED CHANGES IN CORPORATE AND OPERATIONAL STRUCTURE

No changes to Thunder Bay Hydro's corporate and operational structures are planned at the present time.

STATUS OF BOARD DIRECTIVES FROM PREVIOUS BOARD DECISIONS

Thunder Bay Hydro has no outstanding directives from previous Board decisions

COMPANY POLICIES AND REGULATIONS/SERVICE CHARGES

Thunder Bay Hydro's current version of its Conditions of Service is publicly available on the utility's website at www.tbhydro.on.ca. This document is currently in the midst of being updated to provide more detail and clarify certain matters, and once completed, will be posted on the website for public review and comments. As per the DSC Section 2.4.8, Thunder Bay Hydro will provide the Board with a copy of the new Conditions of Service once they are implemented. The copy of the revised document shall include a cover letter that outlines the changes from the prior document, as well as a summary of any public comments on the changes.

The Conditions of Service includes a listing of specific service charges; however, there are no requested changes to the charges in this rate application.

PRELIMINARY LIST OF WITNESSES

While Thunder Bay Hydro requests that this Application be disposed of by way of a written hearing, should a technical conference or an oral hearing be necessary, a list of potential witnesses will be provided at that time.

SUMMARY OF THE APPLICATION

Preamble

Thunder Bay Hydro's vision is:

> ***Thunder Bay Hydro is people working together, providing services of the best value and quality to our customers***.

Thunder Bay Hydro is an electricity distribution company licensed by the Ontario Energy Board to provide electricity distribution services to customers within the City of Thunder Bay and Fort William First Nation Reserve.

Thunder Bay Hydro's priorities are defined in its Corporate Strategy:

> ***Ensure that the Health and Safety of our Employees and Public is the Utility's first priority.***
>
> ***Provide a reliable supply of electricity to the residents and businesses of Thunder Bay.***
>
> ***Protect and grow the value of the utility to our Shareholder.***

In keeping with this vision to pursue health and safety as its top priority, Part of the success of Thunder Bay Hydro's Safety Management System is due to the commitment to creating and maintaining a corporate culture where Health and Safety is the top priority for all employees at all levels. To date, this has been achieved through the implementation of "Target Zero" which is what is internally branded as Thunder Bay Hydro's Safety Management System. Target Zero has been an unqualified success since its introduction Thunder Bay Hydro has supported this program by ensuring awareness and competency regarding safe work practices in everything Thunder Bay Hydro does. Safety education, especially on the risks and hazards of electrical contacts, is a priority for Thunder Bay Hydro, both in-house and in the community. We offer an electrical safety presentation, titled Hi Line Hazards, to local students and service groups.

Purpose and Need

Thunder Bay Hydro's requested revenue requirement for 2013 in the amount of $21,652,791 includes the recovery of its costs to provide distribution services, a Return on Equity ["ROE"] of 7.00% which is lower than then the permitted rate, and the funds necessary to service its debt. The section "ROE" below provides more detail on this chosen rate.

When forecasted energy and demand levels for 2013 are considered, Thunder Bay Hydro estimates that its present rates will produce a deficiency in gross distribution revenue of $1,559,334 for the 2013 Test Year.

Therefore, Thunder Bay Hydro seeks the OEB's approval to revise its electricity distribution rates. The rates proposed to recover its projected revenue requirement and other relief sought are set out in Exhibit 8, Appendix 8-B to this Application.

The information presented in this Application represents Thunder Bay Hydro's forecasted results for its 2013 Test Year. Thunder Bay Hydro is also presenting the forecasted results for 2012 Bridge Year and audited financial information for fiscal 2009, 2010 and 2011.

Timing

The financial information supporting the Test Year for this Application will be Thunder Bay Hydro's fiscal year ending December 31, 2013 (the "2013 Test Year"). However, Thunder Bay Hydro is requesting rates effective May 1, 2013, continuing through April 30, 2014. The Applicant requests that the OEB make its Rate Order by April 15, 2013 in order to achieve this implementation date.

Customer Impact

In preparing this application, Thunder Bay Hydro has considered the impacts on its customers, with a goal of minimizing those impacts. With respect to cost allocation, Thunder Bay Hydro notes that the General Service > 50 kW falls below and the General Service > 1,000 kW, Street Lights and the Unmetered Scattered Load classes are above the applicable thresholds defined by the Board in the March 31, 2012 Report of the Board on Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219). In this application, the rate classes that currently fall

outside of the Board approved target ranges have been brought within the Board's threshold with minimal impact to other classes.

Customer impacts including the percentage average Total Bill Impact and Average Dollar Impact, which include revised distribution rates [monthly service charge and volumetric rates], revised retail transmission rates, revised loss factors, LRAM rate riders, GEA 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 in Table 1-2.1 below, for typical Residential (800 kWh per month) and Commercial (2000 kWh per month) customers. A complete listing of bill impacts for all customer classes at various levels of consumption is provided in Exhibit 8, Appendix 8-C.

Table 1-2.1: Bill Impact: Residential and General Service Less than 50kW

Customer Class: **Residential**

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 9.8500	1	$ 9.85	$ 13.6500	1	$ 13.65	$ 3.80	38.58%
Smart Meter Incremental Rev Req	Monthly	$ 1.8667	1	$ 1.87	$ -	1	$ -	$ (1.87)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0124	800	$ 9.92	$ 0.0119	800	$ 9.52	$ (0.40)	(4.03%)
Smart Meter Disposition Rider	Monthly	$ (1.3167)	1	$ (1.32)	$ (1.3167)	1	$ (1.32)	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.00004	800	$ 0.03	$ -	800	$ -	$ (0.03)	(100.00%)
Stranded Asset Rate Rider	Monthly	$ -	1	$ -	$ 2.2700	1	$ 2.27	$ 2.27	
Sub-Total A				$ 20.35			$ 24.12	**$ 3.77**	**18.53%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0034)	800	$ (2.72)	$ (0.0028)	800	$ (2.24)	$ 0.48	(17.65%)
Tax Charge Rate Rider	per kWh	$ (0.0003)	800	$ (0.24)		800	$ -	$ 0.24	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17.39**			**$ 21.89**	**$ 4.49**	**25.84%**
RTSR - Network	per kWh	$ 0.0064	836	$ 5.35	$ 0.0064	827	$ 5.30	$ (0.05)	(1.01%)
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	836	$ 4.10	$ 0.0048	827	$ 3.97	$ (0.12)	(3.03%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.84**			**$ 31.15**	**$ 4.31**	**16.08%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	836	$ 4.35	$ 0.0052	827	$ 4.30	$ (0.04)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	836	$ 0.92	$ 0.0011	827	$ 0.91	$ (0.01)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	836	$ 5.85	$ 0.0070	827	$ 5.79	$ (0.06)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	800	$ 59.20	$ 0.0740	800	$ 59.20	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	535	$ 33.70	$ 0.0630	530	$ 33.36	$ (0.34)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	150	$ 14.89	$ 0.0990	149	$ 14.74	$ (0.15)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	150	$ 17.75	$ 0.1180	149	$ 17.57	$ (0.18)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 97.40**			**$ 101.61**	**$ 4.20**	**4.31%**
HST		13%		$ 12.66	13%		$ 13.21	$ 0.55	4.31%
Total Bill (including HST)				$ 110.07			$ 114.81	$ 4.75	4.31%
Ontario Clean Energy Benefit [1]				$ (11.01)			$ (11.48)	$ (0.47)	4.27%
Total Bill on RPP (including OCEB)				**$ 99.06**			**$ 103.33**	**$ 4.28**	**4.32%**
Total Bill on TOU (before Taxes)				**$ 104.55**			**$ 108.08**	**$ 3.53**	**3.38%**
HST		13%		$ 13.59	13%		$ 14.05	$ 0.46	3.38%
Total Bill (including HST)				$ 118.14			$ 122.13	$ 3.99	3.38%
Ontario Clean Energy Benefit [1]				$ (11.81)			$ (12.21)	$ (0.40)	3.39%
Total Bill on TOU (including OCEB)				**$ 106.33**			**$ 109.92**	**$ 3.59**	**3.37%**
Loss Factor (%)		4.48%			3.42%				

Customer Class: **General Service Less Than 50 kW**

Consumption 2000 **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 17.8400	1	$ 17.84	$ 27.5800	1	$ 27.58	$ 9.74	54.60%
Smart Meter Incremental Rev Req	Monthly	$ 6.8417	1	$ 6.84	$ -	1	$ -	$ (6.84)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0130	2000	$ 26.00	$ 0.0138	2000	$ 27.60	$ 1.60	6.15%
Smart Meter Disposition Rider	Monthly	$ 3.4917	1	$ 3.49	$ 3.4917	1	$ 3.49	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	$ (0.40)	(100.00%)
Stranded Asset Rate Rider	Monthly		1	$ -	$ 6.5200	1	$ 6.52	$ 6.52	
Sub-Total A				$ 54.57			$ 65.19	**$ 10.62**	**19.46%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0030)	2000	$ (6.00)	$ (0.0035)	2000	$ (7.00)	$ (1.00)	16.67%
Tax Charge Rate Rider	per kWh	$ (0.0002)	2000	$ (0.40)	$ -	2000	$ -	$ 0.40	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 48.17**			**$ 58.19**	**$ 10.02**	**20.80%**
RTSR - Network	per kWh	$ 0.0061	2090	$ 12.75	$ 0.0061	2068	$ 12.62	$ (0.13)	(1.01%)
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2090	$ 9.61	$ 0.0046	2068	$ 9.51	$ (0.10)	(1.01%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 70.53**			**$ 80.33**	**$ 9.79**	**13.89%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2090	$ 10.87	$ 0.0052	2068	$ 10.76	$ (0.11)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2090	$ 2.30	$ 0.0011	2068	$ 2.28	$ (0.02)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2090	$ 14.63	$ 0.0070	2068	$ 14.48	$ (0.15)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1000	$ 87.00	$ 0.0870	1000	$ 87.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0630	1337	$ 84.25	$ 0.0630	1324	$ 83.40	$ (0.85)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	376	$ 37.24	$ 0.0990	372	$ 36.86	$ (0.38)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	376	$ 44.38	$ 0.1180	372	$ 43.93	$ (0.45)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 259.57**			**$ 269.09**	**$ 9.51**	**3.66%**
HST		13%		$ 33.74	13%		$ 34.98	$ 1.24	3.66%
Total Bill (including HST)				$ 293.32			$ 304.07	$ 10.75	3.66%
Ontario Clean Energy Benefit [1]				$ (29.33)			$ (30.41)	$ (1.08)	3.68%
Total Bill on RPP (including OCEB)				**$ 263.99**			**$ 273.66**	**$ 9.67**	**3.66%**
Total Bill on TOU (before Taxes)				**$ 264.45**			**$ 272.28**	**$ 7.83**	**2.96%**
HST		13%		$ 34.38	13%		$ 35.40	$ 1.02	2.96%
Total Bill (including HST)				$ 298.82			$ 307.67	$ 8.85	2.96%
Ontario Clean Energy Benefit [1]				$ (29.88)			$ (30.77)	$ (0.89)	2.98%
Total Bill on TOU (including OCEB)				**$ 268.94**			**$ 276.90**	**$ 7.96**	**2.96%**

Loss Factor (%) 4.48% 3.42%

Transition to Modified International Financial Reporting Standards (MIFRS)

Historically Thunder Bay Hydro has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its financial statements. As stated throughout this application, given the recent announcement by the Canadian Accounting Standards Board (AcSB) "In anticipation of future activities of the International Accounting Standards Board, the Canadian Accounting Standards Board decided at its September 2012 meeting to extend the deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities to 1 January 2014", Thunder Bay Hydro will be deferring the changeover date to International Financial Reporting Standards (IFRS) to January 1, 2014. As such, this application has been prepared using what has been termed "modified CGAAP" (MCGAAP). The actuals for 2009 through to the Bridge Year 2012 have been prepared using CGAAP as historically done and the Test Year 2013 has been prepared using CGAAP as well; however, updating the capitalization and depreciation policy to align with IFRS. Thunder Bay's rationale for preparing this application in this manner is given the recent change by the AcSB, Thunder Bay Hydro's changeover date is now January 1, 2014 and the transition date is January 1, 2013. To allow transparent and useful comparisons to historical expenses, the expenses approved in Thunder Bay Hydro's 2009 Cost of Service application, and to clearly illustrate the impact of the updating of Thunder Bay Hydro's capitalization and depreciation policy, the forecasted 2013 Test Year has been prepared using both Thunder Bay Hydro's historical capitalization and depreciation policy and the updated policies. The change in Thunder Bay Hydro's capitalization and depreciation policies has impacted the calculation of the cost of self-constructed capital assets, depreciation rates, and operating expenses. These changes have impacted the 2013 rate base and the 2013 distribution revenue requirement. Thunder Bay Hydro has provided detailed explanations of these changes in the applicable section of the application.

Smart Meters:

2013 smart meter costs are included the 2013 rate base and revenue requirement. Thunder Bay Hydro is also requesting the recovery of stranded meter amounts as outlined in Exhibit 9 of this Application.

Capital Structure

Thunder Bay Hydro is requesting the continuation of its current deemed capital structure of 40% Equity, 4% Short Term Debt, 56% Long Term Debt.

Return on Equity

Thunder Bay Hydro has assumed a return on equity of 7.00% which is lower than the 9.12% in the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 2, 2012; however, this rate is sufficient to fund the capital investment and operating and maintenance cost requirements. The Corporation of the City of Thunder Bay, the sole shareholder of Thunder Bay Hydro Corporation (shareholder of Thunder Bay Hydro) provides the following governing principle in the Shareholder Declaration:

"DistributionCo shall be operated in accordance with the Rate Minimization Model."

> *Rate Minimization Model* means a Shareholder philosophy of minimizing electricity rates for customers of DistributionCo by having these rates reflect the Shareholder forgoing its allowable regulated return on shareholder equity from DistributionCo and forgoing payment of interest or principal on long term debt held in DistributionCo by the Shareholder.

Consistent with this principle, essentially to keep electricity rates as low as possible and to encourage economic development by foregoing debt and dividend payments, the Note Payable to the City of Thunder Bay was set up without any provision for the payment of interest or the repayment of principal. Additionally, the Corporation of the City of Thunder Bay does not seek a dividend from Thunder Bay Hydro.

Capital Expenditures

Thunder Bay Hydro continues to expand and reinforce its distribution system in order to maintain the reliability for existing customers and meet the demand of new and existing customers in its service territory. Given that Thunder Bay Hydro's load has been relatively flat for several years, the increase in demand comes mainly from distribution system replacements/upgrades needed in existing areas. Thunder Bay Hydro's core business is the safe, reliable delivery of electricity to the residents and businesses of Thunder Bay. To achieve this, a well-developed, long-term approach to infrastructure investment and maintenance is critical. As a direct result, Thunder Bay Hydro's capital spending forecasted in 2012 and 2013 is increasing at a similar pace as in previous years (exclusive of the New Maintenance Facility scheduled for 2013 for $3.3M (see Exhibit 2, Tab 3, Schedule 1 for more detail) and is in line with its 20 year capital plan as discussed in its Asset Management Plan (AMP) in Exhibit 2, Appendix 2-A.

As discussed in rate filing EB-2008-0245, Thunder Bay Hydro conducted a complete risk assessment for all overhead lines, underground equipment, cables and substations. Since the 2007 inspection, Thunder Bay Hydro has been methodically narrowing the scope of the inspection in order to inspect each asset with greater scrutiny. Subsequent to the 2007 inspection, Thunder Bay Hydro has inspected all substations in accordance with the regime specified by Appendix C of the Distribution System Code and has inspected all other outside distribution system assets in keeping with a 3 year cycle. The scope, objectives, and findings of the Thunder Bay Hydro's Asset Condition Assessment are detailed in the Thunder Bay Hydro's AMP, Exhibit 2, Appendix 2-A.

In general, the Asset Condition Assessment findings have provided a critical input to Thunder Bay Hydro's asset replacement strategy and have been used to establish capital replacement rates necessary for the sustainment of; overhead distribution assets, underground distribution assets, and distribution station assets. As a result of this sustainment rate analysis (refer to Thunder Bay Hydro's AMP Sections 4, 5, and 6) an escalated capital replacement rate has been requested (refer to Thunder Bay Hydro's AMP Section 7). The intention of the capital replacement gradient is to recover the overall distribution asset health such that an equivalent

number of new assets are entering the distribution system as are reaching end of life (as opposed to its present state where a disproportionate number of assets are approaching end of life prior to their planned replacement).

Thunder Bay Hydro has applied the proposed capital replacement gradient to its ongoing, rolling 20-year capital expenditure plan. To date this plan includes detailed project definitions out to 2015 with project concepts extending to 2023.

Operating and Maintenance Costs

Cost reduction and efficiency are always an important part of expenditure decisions at Thunder Bay Hydro. Operating and maintenance costs for this 2013 Cost of Service Application have been updated to reflect the impact of inflation, cost savings produced by operational efficiencies, growing demands associated with aging infrastructure, increasing frequency/severity of significant weather events, and work generated by an increasingly rigorous asset inspection/management regime. Other significant costs drivers include competition for skilled labour and succession planning for a significant number of staff retirements and the subsequent transference of their knowledge and skills.

In general, Thunder Bay Hydro's OM&A budget has remained relatively static since 2010 however the allocation of the total budget to its associated sub-categories has been updated to more effectively reflect actual expenditures.

BUDGET OVERVIEW

Thunder Bay Hydro compiles budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense forecast and capital budget forecast. This budget information is compiled for both the 2012 Bridge Year and the 2013 Test Year.

Thunder Bay Hydro began preparing its 2012 forecast and 2013 budget in May 2012 and they were both approved by Management in August 2012. The budget was presented to Thunder Bay Hydro's Board at the September 20, 2012 Board meeting. The Board of Directors approved the 2013 Budget.

In preparation of the budget for Cost of Service rate application purposes, Thunder Bay Hydro notes that it has annualized certain one-time costs that are planned to occur between 2013 and 2016 in the 2013 Test Year as per established Board practice. Costs that have been annualized include regulatory costs associated with the preparation and follow-up of the 2013 Cost of Service rate application; interest on long-term debt; non-annual safety related purchases, one-time consulting costs as well as one-time demolition costs. These will be discussed in more detail in Exhibit 4.

Revenue Forecast

Thunder Bay Hydro's energy sales and revenue forecast model were updated to reflect more recent information. This model was then used to prepare the revenues sales and throughput volume and revenue forecast at existing rates for fiscal 2012 and 2013. The forecast is weather normalized as outlined in Exhibit 3, Tab 2, Schedule 1 and considers such factors as average weather conditions and status quo for the economic conditions in the area serviced by Thunder Bay Hydro.

Operating Maintenance and Administration ("OM&A") Expense Forecast

The OM&A expenses for the 2012 Bridge Year and the 2013 Test Year have been based on an in-depth review of operating priorities and requirements and is strongly influenced by prior year experience, year-to-date results and expected changes for the forecast periods. Each item is reviewed account by account for each of the forecast years with indirect costs allocated to direct costs for budget presentation.

Capital Budget

The capital budget forecast 2012 and 2013 is influenced by, among other factors, the highest priority capital requirements and Thunder Bay Hydro's capacity to finance capital projects. Indirect costs are allocated to direct costs in the capital budget. All proposed capital projects are assessed within the framework of their capital budget priority and are outlined in Exhibit 2, Tab 3, Schedule 2.

Thunder Bay Hydro's Budget Process

The following comments provide an overview of Thunder Bay Hydro's budgeting process.

Overall Budget Process

The budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is typically approved by the end of October and forwarded to the shareholder, The Corporation of the City of Thunder Bay. The budget then provides the plan against which actual results are evaluated.

Responsibilities

- It is the responsibility of the Finance Division to coordinate the development of the operating budget, capital budget and forecast processes.
- Each division is responsible for preparing its operating budget, capital budget, and rolling forecasts.
- The Vice President of Finance and the President review the budget in detail, discussing with the respective Vice Presidents as necessary.
- The President is responsible for presenting and recommending the budget to the Board of Directors for approval.
- It is the responsibility of the Board of Directors, on behalf of the shareholders, to approve the budget.

The budget is an important planning tool for Thunder Bay Hydro. It puts capital and operational plans into a common financial plan. The budget plan is done within our accounting software

package and is budgeted at the element level. The following is our accounting software account structure:

Account Number Structure

Account Number 001-6556-420.42-01
Fund 001 THUNDER BAY HYDRO
Division 65 Operating
Department 56 O/H Lines & Feeders
Activity Basic 42 Distribution System
Sub-Activity 0 Distribution System
Element 42 Salary/Wages
Object 01 Regular

The divisional Budget Plans represent the output of the detailed departmental work plans based on required activities for the year. The final document provides a summarized package of the organization's budget that ensures that appropriate resources are designated for the various capital and operational needs of the utility for the coming year.

Budget Review Process:

Thunder Bay Hydro's budget review process is as follows:

- The budget process starts with the issuance of directive memos to the Vice Presidents and the President outlining the approach, expectations and timelines for the budget process.
- Each department budget is reviewed and approved by the corresponding division Vice President and submitted to the Accounting Department.
- The Accounting Department consolidates all departmental work plan budgets to produce budget reports by division to be reviewed by the corresponding Executive Team member(s).
- The Vice President, Finance presents the draft budget to the Executive Team member(s) for a comprehensive review. Highlights of new staff complement and the rationale for such, anomaly costs and significant cost increases ongoing, are some of the issues that are discussed. The Vice President Finance presents the revised

budget package to the President for further review and adjustment, bringing in the respective Vice President as necessary.

- The final budget package is presented to the President for approval.

The Actual-to-Budget Review Process:

Once the budget is final, each Division Vice President reviews and tracks both operating and capital progress against the budget on a monthly basis. The Finance Department provides summary and/or detailed department cost information to the Vice Presidents on a monthly basis providing the budget, the costs to date, the percentage of budget spent to date as well as the percentage of the budget year that has elapsed. Explanations of significant/unusual variances are verbally discussed between Finance and the respective Vice Presidents as well as the President and respective Vice Presidents.

Further, quarterly financial statements are presented to the Board of Directors.

Economic Assumptions

Thunder Bay Hydro's service area has had a relatively static population for many years and there has been no significant loss or growth of customers since the last Cost of Service Rate application. As a result, minimal growth in customers or usage has been assumed while preparing this application and primarily focuses on the maintenance of the utility's assets.

CHANGES IN METHODOLOGY

In its current application Thunder Bay Hydro has no changes in methodology since its 2009 Cost of Service application.

REVENUE DEFICIENCY

Thunder Bay Hydro has provided detailed calculations supporting its 2013 revenue deficiency. Thunder Bay Hydro's net revenue deficiency is $1,559,334. Table 1-2.3 on the following page provides the revenue deficiency calculations for the 2013 Test Year at Existing 2012 Board-approved rates and the 2013 Test Year Revenue Requirement. For informational purposes, a schedule of the most recent Board-approved revenue requirement is found below in Table 1-2.2.

Table 1-2.2 – EB-2008-0245 Rate Year 2009

		Revenue Requirement	
Line No.	**Particulars**	**Application**	**Per Board Decision**
1	OM&A Expenses	$11,913,122	$11,935,063
2	Amortization/Depreciation	$4,443,745	$4,443,745
3	Property Taxes	$ -	$ -
4	Capital Taxes	$168,569	$170,284
5	Income Taxes (Grossed up)	$726,890	$705,382
6	Other Expenses	$ -	$ -
7	Return		
	Deemed Interest Expense	$176,530	$122,801
	Return on Deemed Equity	$1,214,089	$1,226,472
8	Distribution Revenue Requirement before Revenues	$18,642,945	$18,603,746
9	Distribution revenue	$17,145,155	$17,105,956
10	Other revenue	$1,497,790	$1,497,790
11	**Total revenue**	$18,642,945	$18,603,746
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0 **(1)**	$ - **(1)**

Table 1-2.3: Calculation of Revenue Deficiency (MCGAAP)

Thunder Bay Hydro Electricity Distribution Inc. Revenue Deficiency Determination			
Description	**2012 Bridge Actual**	**2013 Test Existing Rates**	**2013 Test - Required Revenue**
Revenue			
Revenue Deficiency			**1,559,334**
Distribution Revenue	21,217,869	18,341,720	18,341,720
Other Operating Revenue (Net)	1,210,942	1,751,736	1,751,736
Total Revenue	**22,428,811**	**20,093,456**	**21,652,791**
Costs and Expenses			
Administrative & General, Billing & Collecting	6,825,827	7,146,549	7,146,549
Operation & Maintenance	6,943,137	7,511,666	7,511,666
Depreciation & Amortization	6,860,539	3,247,244	3,247,244
Charitable Donation (LEAP)	-	24,200	24,200
Deemed Interest	379,160	1,080,120	1,080,120
Total Costs and Expenses	**21,008,662**	**19,009,779**	**19,009,779**
Utility Income Before Income Taxes	**1,420,149**	**1,083,677**	**2,643,012**
Income Taxes:			
Corporate Income Taxes	375,757	-	-
Total Income Taxes	**375,757**	**0**	**0**
Utility Net Income	**1,044,391**	**1,083,677**	**2,643,012**
Income Tax Expense Calculation:			
Accounting Income	1,420,149	1,083,677	2,643,012
Tax Adjustments to Accounting Income	601,578	(2,831,251)	(2,831,251)
Taxable Income	**2,021,726**	(1,747,574)	(188,239)
Income Tax Before Tax Credits	**535,757**	**0**	0
Tax Credits	**160,000**	**0**	**0**
Income Tax Expense	375,757	0	0
Tax Rate Refecting Tax Credits	26.50%	0.00%	0.00%
Actual Return on Rate Base:			
Rate Base	86,625,862	94,393,281	94,393,281
Interest Expense	379,160	1,080,120	1,080,120
Net Income	1,044,391	1,083,677	2,643,012
Total Actual Return on Rate Base	**1,423,551**	**2,163,797**	**3,723,132**
Actual Return on Rate Base	1.64%	2.29%	3.94%
Required Return on Rate Base:			
Rate Base	86,625,862	94,393,281	94,393,281
Return Rates:			
Return on Debt (Weighted)	0.73%	1.91%	1.91%
Return on Equity	3.75%	7.00%	7.00%
Deemed Interest Expense	379,160	1,080,120	1,080,120
Return On Equity	1,299,388	2,643,012	2,643,012
Total Return	**1,678,548**	**3,723,132**	**3,723,132**
Expected Return on Rate Base	1.94%	3.94%	3.94%
Revenue Deficiency After Tax	**254,997**	**1,559,334**	**0**
Revenue Deficiency Before Tax	**346,934**	**1,559,334**	**0**

CAUSES OF REVENUE DEFICIENCY

Thunder Bay Hydro's revenue deficiency is calculated as $1,559,334. Thunder Bay Hydro's calculation of its 2013 revenue deficiency is provided in Exhibit 1, Tab 2, Schedule 4.

The revenue deficiency is primarily the result of:

- Increases in OM&A costs since Thunder Bay Hydro's last cost of service in 2009. For the 2013 Test Year Thunder Bay Hydro is forecasting OM&A expenses increasing at a compound annual growth rate of 2.9% per year since 2009 Board Approved, under CGAAP. In light of the results of the OEB led Kinetrics Depreciation Report and required changes in preparation for the transition to Modified International Financial Reporting Standards (MIFRS) in 2014, Thunder Bay Hydro has made changes to its capitalization and depreciation policies in 2013 in order to be compliant with the new standards. The transition from CGAAP to MCGAAP (as explained in Exhibit 1, Tab 2, Schedule 1, page 3 will increase operating expenses an additional $1,257,255.

- The remaining cost increase of $1,516,914 is explained as follows:

  - approximately $326,000 incremental costs related to the Government's Smart Meter Initiative which effective January 1, 2012 are included in rate base;

  - Increased labour costs of approximately $230,000, representing an increase of 5% over the 2009 Board Approved COS application. The increases are a result of increased complement of I FTE in the Finance Staff (Business & Regulatory Analyst); apprentice complement increase for succession planning and wage progressions and the following union contract negotiation increases shown in Table 1-2.4:

Table 1-2.4 –Union Negotiated Increases

Contract Period	Rate for Outside Staff*	Rate for Inside Staff*
May 1, 2009-April 30, 2010	4.0% or 2%	3.5% or 2%
May 1, 2010-April 30, 2011	3.0% or 1.5%	3.0% or 1.5%
May 1, 2011-April 30, 2012	3.0% or 1.5%	3.0% or 1.5%
May 1, 2011-April 30, 2012	3.0% or 1.5%	3.0% or 1.5%
*The rates vary accordingly to employee groups.		

(See discussion at Exhibit 4, Tab 2, Schedule 4, page 3);

- Approximately $154,000 increase in benefits, most notably the OMERs pension cost which increases $45,000 from 2012 alone;

- Approximately $280,000 in overtime costs (Thunder Bay Hydro is continually reviewing overtime requirements with the objective of reducing such and the 2013 Test Year is approximately $26,000 below the five year historical overtime average as shown in Table 1-2.5 below);

Table 1-2.5 – Overtime Costs

Overtime							
2007 Actuals	2008 Actuals	BA2009	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
$414,416	$346,802	$93,195	$397,537	$433,779	$408,494	$417,482	$373,985
	Average of the 2007-2011 Actual Overtime				**$400,205**		

- Approximately $198,500 increased I.T. Department Costs ($127,000 is labour, overtime and benefits, $75,000 of which was a market adjustment to labour costs in 2009) and the remaining is an increase in hardware and software maintenance agreements and subscriptions reflective of required new hardware/software acquisitions. The most significant of these agreements and subscriptions relate to new servers, storage area networks, media library hardware as well as new communication and document management software systems;

- Approximately $80,000 increase in the Forestry Management outside service costs. This is in keeping with our Asset Management Plan which commenced with the 2009 COS application;

- The balance of the increase $248,414 is a number of drivers under the materiality threshold of $85,000.

See also Exhibit 4, Tab 2, Schedule 3 for the cost driver review.

- Depreciation expense has reduced by $1,223,318 since the last rebasing in 2009. Included in this amount is an increase as a result of the normal annual increase in property, plant and equipment, approximately $600,000 increase due to the smart meter assets inclusion in Rate Base offset by a reduction due to the change to MCGAAP of $2,440,000.

- PILs have reduced by $876,000 since the last rebasing in 2009. Thunder Bay Hydro is not including an amount for PILs in this application. The change in depreciation and OM&A expenses as a result of Thunder Bay Hydro's change in the depreciation and capitalization policy (MCGAAP) to align with the coming IFRS Standards have reduced taxable income such that no PILs funding is necessary. Thunder Bay Hydro's tax adjustment for depreciation is significantly lower than the capital cost allowance deduction resulting in a negative taxable income. Canada Revenue Agency relies on "generally accepted accounting principles" (GAAP) and in light of the coming IFRS Standards changing the Canadian GAAP, Canada Revenue Agency may adjust the capital cost allowance rate on distribution assets (currently at 8% from 4% in 2005) to more appropriate align. PILs funding Included in distribution rates in the 2009 COS was $876,000.

- Thunder Bay Hydro's deemed interest on long-term debt has increased $883,611 after adjusting the 2009 COS capital parameter from 52.7% to 56%. Thunder Bay Hydro has existing debt and is currently in the process of securing a financing agreement for the next five years ending December 31, 2016. As discussed in Exhibit 5, the interest on long-term debt has been recorded at $1,001,585 which is the annualized amount based on the forecasted debt load for 2012 to 2016.

- Thunder Bay Hydro has increased the rate of return on equity from 3.75% to 7% which has increased the Revenue Requirement by $1,323,067 after adjusting the 2009 COS capital parameter from 43.3% to 40%. As mentioned throughout this application, Thunder Bay

Hydro operates on the "Rate Minimization" model and does not earn a return for purposes of shareholder dividends. As Thunder Bay Hydro's investment in property, plant and equipment has increased above the annual depreciation and net income amount, cash flow (net of the regulatory liabilities) has been considerably reduced such that external financing to fund the capital investment is and will continue to be required.

- Offsetting the foregoing increases to Revenue Deficiency is the approval of the Smart Meter Incremental Revenue Requirement (SMIRR) effective January 1, 2012. This increased distribution rates for both the residential and general service less than 50 kW class. The total SMIRR approved in rates amounted to $1,364,127.

- In this application Thunder Bay Hydro is applying for a rate base of $94,393,281 compared to a rate base of $75,533,273 which was approved during Thunder Bay Hydro's 2009 cost of service application which amounts to an increase of $18,860,008. The cost drivers of this increase are the following:

  - The average NBV of the property, plant and equipment has increased $17,853,747. Three major transactions impacting the NBV are the smart meters rolling into the rate base (2012 closing NBV increase net of the removal of the stranded assets in 2009 is $4,553,065) and the new maintenance facility ($3,300,000) in the 2013 Test Year offset by the reduction resulting from the change to MCGAAP ($ 2,373,904). The three transactions impact the rate base by approximately $4,400,000. The balance of the increase in the average NBV of the property, plant and equipment is the result of the annual investment exceeding the annual amortization on the assets as per Thunder Bay Hydro's asset management plan. Thunder Bay Hydro is committed to ensuring the reliability of the distribution system and will continue to invest in capital infrastructure in 2012 and 2013 at a level exceeding depreciation

  - Working capital allowance has increased by $1,006,261 from the 2009 Board Approved amount due to increases in the cost of power and increases in the applicant's operating expenses (including $$141,072 relating to the change to MCGAAP) offset by a reduction in the working capital allowance rate from 15% to 13%. .

See also Exhibit 2 for the Rate Base review.

FINANCIAL STATEMENTS – 2009, 2010 and 2011

Thunder Bay Hydro's Audited Financial Statements accompany this Exhibit as Appendix 2-B.

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND REGULATORY ACCOUNTING:

The following Tables 1-3.1 – 1-3.3, reconciles the 2009 Audited Financial Statements to the regulatory financial results filed in this Application.

Table 1-3.1 - 2009 Audited F/S and OEB Net Income Reconciliation

2009 Audited F/S and OEB Net Income Reconciliation		
Net income per audited F/S	$	4,657,930
Add back 2008 SM* Correction	$	(1,475)
	$	4,656,455
2009 SM Correction	$	4,392
2009 SM Carrying charge correction	$	(273)
2009 Carrying correction #2	$	86
	$	4,660,660
Per 2009 OEB Submission	$	4,660,661
	$	(1)
** SM = Smart Meter*		

Table 1-3.2 - 2010 Audited F/S and OEB Net Income Reconciliation

2010 Audited F/S and OEB Net Income Reconciliation		
Net Income per audited F/S	$	481,532
Add back 2009 Smart Meter Correction	$	(4,392)
	$	477,140
2010 Smart Meter Correction	$	(721)
2010 Long-term Load Transfer Accrual reversal for billed basis	$	(4,126)
Net Income Per 2010 OEB submission	$	472,293
		4,847

Table 1-3.3 - 2011 Audited F/S and OEB Net Income Reconciliation

2011 Audited F/S and OEB Net Income Reconciliation	
Net Income per audited F/S	$ 2,030,391
Net Income Per 2010 OEB submission	**$ 2,030,391**
	$ -

Please note that the reconciliation between the Audited Financial Statements and the Fixed Asset Continuity Schedules is found in Exhibit 4, Table 4-2.29.

PRO FORMA FINANCIAL STATEMENTS - 2012 AND 2013

The Pro Forma Statements for the 2012 Bridge Year and the 2013 Test Year accompany this Schedule as Appendix 1-C and Appendix 1-D respectively.

RECONCILIATION BETWEEN PRO FORMA STATEMENTS AND REVENUE DEFICIENCY STATEMENTS

No reconciliation is required between the 2013 Pro Forma statement and the revenue deficiency statement.

INFORMATION ON PARENT AND SUBSIDIARIES

The Thunder Bay Hydro Corporation 2011 Annual Report, which describes the activities and consolidated financial results of Thunder Bay Hydro's group of companies, is included in Appendix 1-G to this schedule.

A more detailed description of the group of companies is set out in Exhibit 1, Tab 1, Schedule 13 (Corporate Entities Relationships Chart).

Thunder Bay Hydro advises that it does not prepare a Management Discussion and Analysis ("MD&A") Report.

MATERIALITY THRESHOLDS:

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued by the Board June 28, 2012 states the relevant default materiality threshold as:

"0.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million."

As Table 1-4.1 indicates, the average materiality during the past 3 years and including the Board Approved amount for Thunder Bay Hydro is $84,731. To ensure a thorough analysis, all variances greater than $85,000 have been analyzed.

Table 1-4.1 - Materiality Threshold

	2009 Board-Approved	2009 Actual	2010 Actual	2011 Actual
Distribution Revenue Requirement	$17,105,956	$16,779,398	$16,504,064	$17,395,065
0.50%	$85,530	$83,897	$82,520	$86,975
			Average	$84,731

Revenue Requirement Work Form ("RRWF")

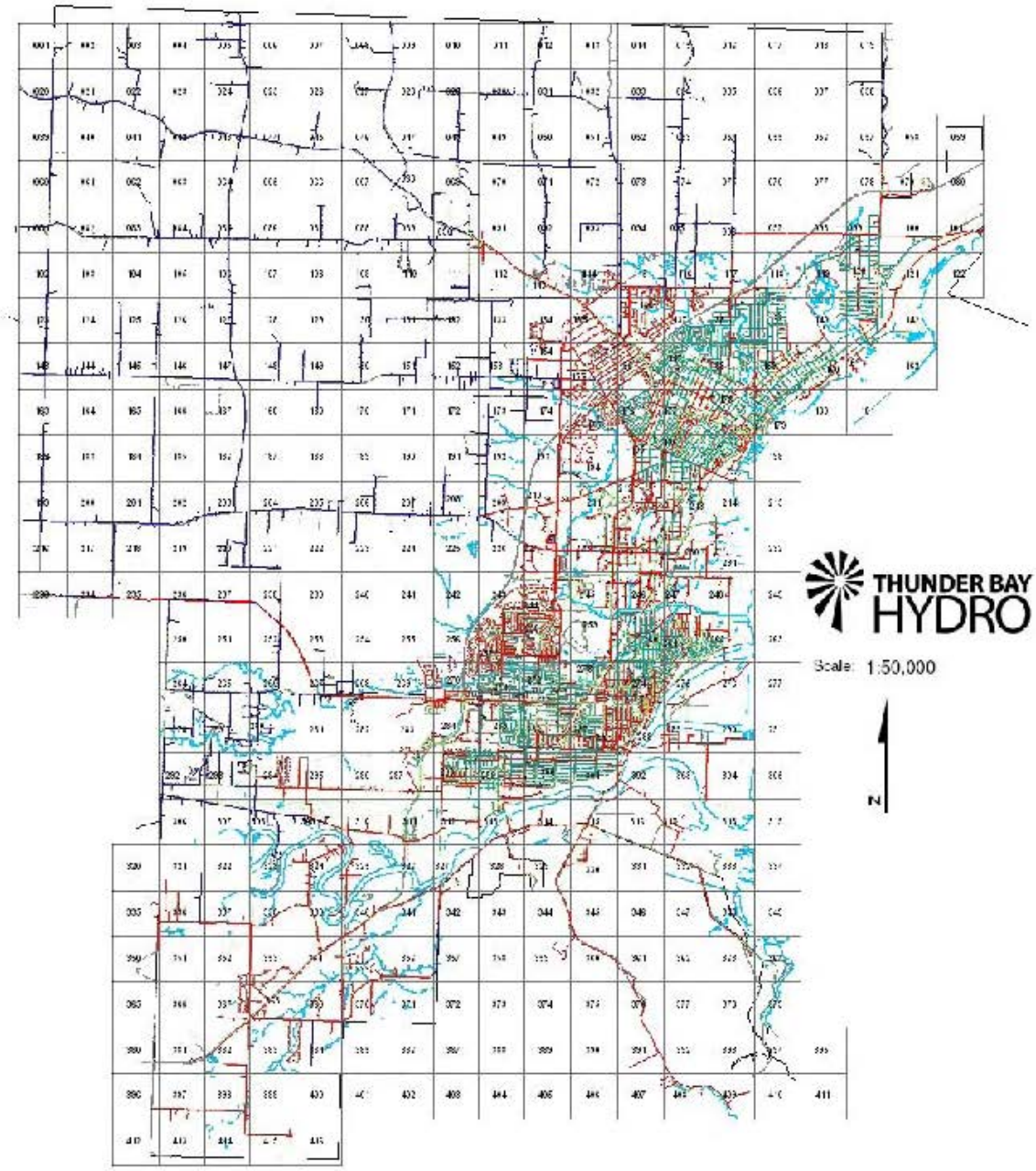
Please see Appendix 1-F for Thunder Bay Hydro's RRWF.

APPENDICES

APPENDIX 1-A

Map of Distribution Service Territory/Map of Distribution System

MAP OF DISTRIBUTION SERVICE TERRITORY/MAP OF DISTRIBUTION SYSTEM



APPENDIX 1-B
Copies of Thunder Bay Hydro Electricity Distribution Inc. Audited Financial Statements for 2009, 2010 and 2011

Grant Thornton

Financial Statements

Thunder Bay Hydro Electricity Distribution Inc.

December 31, 2009

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Grant Thornton

Auditors' Report

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To the Shareholder of

Thunder Bay Hydro Electricity Distribution Inc.

We have audited the balance sheet of Thunder Bay Hydro Electricity Distribution Inc. as at December 31, 2009 and the statements of operations and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. 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 plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Thunder Bay, Canada
March 31, 2010

Chartered Accountants
Licensed Public Accountants

Audit • Tax • Advisory
Grant Thornton LLP. A Canadian Member of Grant Thornton International Ltd

Thunder Bay Hydro Electricity Distribution Inc.
Balance Sheet

As at December 31	2009	2008
	$	$
ASSETS		
Current		
Cash and cash equivalents	**9,375,065**	8,220,174
Investments	**—**	5,014,176
Accounts receivable *[note 20]*	**7,300,578**	6,687,170
Unbilled revenue	**12,347,110**	11,156,565
Payments in lieu of corporate income taxes receivable	**1,392,997**	1,603,547
Due from associated companies *[note 3]*	**803,659**	294,100
Stores inventory	**1,571,869**	1,441,528
Prepaid expenses	**199,595**	247,792
Total current assets	**32,990,873**	34,665,052
Other		
Intangible assets *[note 4]*	**951,380**	670,791
Regulatory assets *[note 5]*	**8,796,956**	1,329,248
Future income tax assets *[note 6]*	**6,200,000**	—
Total other assets	**15,948,336**	2,000,039
Property, plant and equipment, at cost		
Property, plant and equipment, net *[note 7[a]]*	**69,078,584**	68,388,839
Capital contributions, net *[note 7[b]]*	**(8,315,003)**	(7,494,028)
Construction-in-progress	**1,276,696**	962,146
Property, plant and equipment, net	**62,040,277**	61,856,957
	110,979,486	98,522,048

See accompanying notes to the financial statements.

On behalf of the Board:

Director

Director

	2009	2008
	$	$
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	**11,967,880**	11,203,312
Debt retirement charges payable	**546,426**	561,669
Deferred revenue and contributions	**332,639**	327,641
Customer deposits	**2,387,561**	1,980,998
Current portion of long-term debt *[note 8]*	**367,673**	—
Total current liabilities	**15,602,179**	14,073,620
Long-term		
Regulatory liabilities *[note 5]*	**4,033,108**	7,769,671
Employee future benefits liability *[note 10]*	**2,803,924**	2,669,092
Note payable to The Corporation of the City of Thunder Bay *[note 11]*	**33,490,500**	33,490,500
Asset retirement obligation *[note 12]*	**525,119**	512,186
Long-term debt *[note 8]*	**7,484,747**	—
Future income tax liabilities *[note 6]*	**2,375,000**	—
Total long-term liabilities	**50,712,398**	44,441,449
Shareholder's equity		
Share capital		
Authorized		
Unlimited common shares		
Issued		
1,000 common shares	**34,931,625**	34,931,625
Retained earnings	**9,733,284**	5,075,354
Total shareholder's equity	**44,664,909**	40,006,979
	110,979,486	98,522,048

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Operations and Retained Earnings

Year ended December 31	2009	2008
	$	$
REVENUES AND FLOW-THROUGH CHARGES		
Flow-through charges plus distribution revenues	**91,153,222**	82,805,390
Flow-through costs of energy	**(74,346,574)**	(66,488,637)
Distribution revenue	**16,806,648**	16,316,753
Other operating revenue *[note 13]*	**1,979,864**	2,205,444
	18,786,512	18,522,197
EXPENSES		
Administration *[schedule]*	**5,644,649**	5,563,685
Amortization *[note 14]*	**4,598,624**	4,559,926
Conservation and demand management	**—**	42,129
Operations and maintenance *[schedule]*	**6,731,194**	6,495,463
Provision for payments in lieu of capital tax	**178,000**	173,500
	17,152,467	16,834,703
Earnings before the following	**1,634,045**	1,687,494
Carrying charges on regulatory assets/liabilities, net	**67,115**	154,807
Earnings before provision for taxes	**1,566,930**	1,532,687
Payments in lieu of corporate income taxes *[note 6]*		
Current	**734,000**	963,000
Future taxes recoverable	**(3,825,000)**	—
	(3,091,000)	963,000
Earnings for year	**4,657,930**	569,687
Retained earnings, beginning of year	**5,075,354**	4,505,667
Retained earnings, end of year	**9,733,284**	5,075,354

See accompanying notes to the financial statements.

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Cash Flows

Year ended December 31	2009	2008
	$	$
OPERATING ACTIVITIES		
Earnings for year	**4,657,930**	569,687
Add charges (deduct credits) to operations not involving a current payment (receipt) of cash		
Accretion expense related to asset retirement obligation	**12,933**	—
Amortization of property, plant and equipment *[note 14]*	**4,900,680**	4,809,969
Amortization of intangible assets *[note 14]*	**65,006**	112,553
Increase in employee future benefits	**134,832**	191,792
Gain on disposal of property, plant and equipment	**(14,640)**	(4,150)
Future taxes recoverable	**(3,825,000)**	—
	5,931,741	5,679,851
Net change in non-cash working capital balances related to operations *[note 16[a]]*	**(1,024,220)**	1,867,581
Cash provided by operating activities	**4,907,521**	7,547,432
INVESTMENT ACTIVITIES		
Proceeds on sale of property, plant and equipment	**14,640**	4,150
Additions to intangible assets	**(345,595)**	(514,495)
Additions to property, plant and equipment, net *[note 16[b]]*	**(6,986,891)**	(5,986,866)
Sale (purchase) of investments	**5,014,176**	(5,014,176)
Cash used in investment activities	**(2,303,670)**	(11,511,387)
FINANCING ACTIVITIES		
(Increase) decrease in regulatory assets *[note 16[c]]*	**525**	(40,030)
Increase (decrease) in regulatory liabilities	**(3,736,563)**	326,854
Repayments of obligation under capital lease	**—**	(9,385)
Repayments of bank loan	**(147,580)**	—
Unapplied loan proceeds - restricted cash	**412,474**	—
Non-cash stranded asset cost included in regulatory assets	**2,022,184**	—
Cash provided by (used in) financing activities	**(1,448,960)**	277,439
(Decrease) increase in cash and cash equivalents during year	**1,154,891**	(3,686,516)
Cash and cash equivalents, beginning of year	**8,220,174**	11,906,690
Cash and cash equivalents, end of year	**9,375,065**	8,220,174
Represented by		
Cash - unrestricted	**8,962,591**	8,220,174
Cash - restricted	**412,474**	—
	9,375,065	8,220,174

See accompanying notes to the financial statements.

GENERAL

Thunder Bay Hydro Electricity Distribution Inc. ("the Corporation") is a wholly-owned subsidiary company of Thunder Bay Hydro Corporation, providing electrical distribution services to the inhabitants of The Corporation of the City of Thunder Bay and the Fort William First Nation Reserve, as regulated by the Ontario Energy Board ("OEB").

1. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and reflect the significant accounting policies summarized below.

Rate setting and regulation

The rates of the Corporation's electricity distribution are subject to regulation by the OEB. The cost of power and all costs other than distribution related to the operations of the electricity grid including transmission, connection and administration costs are flowed through to the consumer.

The distribution revenue is designed to recover the costs incurred by the Corporation in delivering electricity to customers. Distribution rates are regulated by the OEB and typically comprise a monthly service charge and a volumetric charge.

The Corporation's distribution rates, effective May 1, 2009, were approved by the OEB in a decision dated June 3, 2009.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and in banks.

Stores inventory

Stores inventory consists principally of maintenance and construction materials and is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

Property, plant and equipment

Property, plant and equipment are stated at cost less accumulated amortization. In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation or amortization, with no gain or loss reflected in results of operations. Gains or losses on retirement or disposition of assets which are not grouped are credited or charged to other operating revenue. Amortization is provided on a straight-line basis for property, plant and equipment over their estimated service lives at the following annual rates:

Buildings	2%
Distribution and transformation equipment	3% to 4%
Other assets	10% to 20%
Rolling stock	12½% to 20%

As necessary, these assets are tested for impairment.

Intangible assets

Intangible assets represent computer applications software and capital contributions. These assets are carried at cost net of accumulated amortization.

Amortization is provided on a straight-line basis for intangible assets over their estimated useful lives at the following rates:

Computer software	20%
Capital contributions	4%

Pension plan

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 *[note 15]*. The Corporation recognizes the expense related to this plan as contributions are made.

Other post-employment benefits

Employee future benefits provided by the Corporation include medical and life insurance benefits and accumulated sick leave credits. These plans provide benefits to certain employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render the services. Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. Actuarial gains (losses) are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in earnings in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in earnings for the period in which a settlement occurs.

Revenue recognition

Distribution revenue is recognized on the basis of regular meter readings. Estimates of customer usage since the last meter reading date, to the end of the year are recorded as unbilled revenue.

Pole line revenue is recognized based on annual contracted rates and agreed-upon pole counts.

The Corporation has entered into Conservation Demand Management (CDM) agreements with the Ontario Power Authority ("OPA") for the period from 2007 to 2010. Performance fees are recognized as the related CDM programs are delivered.

Revenues from Lost Revenue Adjustment Mechanism and Shared Savings Mechanism approved in rates are recognized on a accrual basis.

Other revenue is recognized when the requirements as to performance for transactions involving the sale of goods or services are met and ultimate collection is reasonably assured at the time of performance.

Construction-in-progress

Construction-in-progress is comprised of the costs of assets not yet placed into service, assets under construction, and pre-construction activities related to projects expected to be completed. These amounts are not amortized. Upon energization of assets the amounts are transferred to property, plant and equipment and are amortized on a straight-line basis over the expected service life of the asset.

Contributions in aid of construction

Capital contributions are required contributions received from outside sources, used to finance additions to property, plant and equipment. Capital contributions are credited against property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related property, plant and equipment.

Customer deposits

Customers' advance deposits are cash collections from customers or Energy Retailers to guarantee the payment of energy-related bills. The deposits bear interest at prime less 2% and is paid annually to customers.

Customer deposits also include collections from renewable generation customers for connection cost and capacity allocation deposits, as dictated by the OPA. Interest may be payable on the capacity allocation deposit upon connection of the renewable generation facility.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from those estimates.

Corporate income and capital taxes

Under the *Electricity Act, 1998*, the Corporation is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income taxes 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.

Current income taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at amounts receivable or payable from/to the OEFC.

Future income taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

Asset retirement obligation

The Corporation recognizes a liability for the future removal and handling cost for contamination in distribution equipment and units in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is amortized and the liability is adjusted annually for the discount applied upon initial recognition of the liability ("accretion expense") and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ("ARO") is incurred and when the fair value is determined.

Financial instruments

On initial recognition, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between willing parties.

The Corporation classifies its financial instruments as follows and uses the following methods and assumption to estimate the fair value of each class of financial instruments for which carrying amounts are included in the Balance Sheet:

- Cash is classified as "Held-for-Trading" and is measured at fair value.
- Investments comprising short-term investments, are classified as "Held-to-Maturity Investments" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value.
- Accounts receivable are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Due from associated companies are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Customers' advance deposits are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity.

- Note payable to The Corporation of the City of Thunder Bay is classified as "Other Financial Liabilities". It was originally recognized in accordance with CICA 3840, *Related Party Transactions*, being the amount of consideration established by contract. There is no requirement to fair value the amount on initial recognition because of the non-market rate of interest. Subsequent measurements are determined in accordance with CICA 3840 which provides the basis for subsequent measurement at amortized cost. The only changes to the amount initially recognized are changes in principal balances.

- Long-term debt is classified as "Other Financial Liabilities" and was initially measured at cost. Subsequent measurements are recorded at amortized cost using the effective interest method.

2. ACCOUNTING CHANGES

Rate-Regulated Operations

Effective January 1, 2009, the Corporation adopted amended CICA Handbook Section 1100 - *Generally Accepted Accounting Principles* [Handbook Section 1100], Handbook Section 3465 - *Income Taxes* [Handbook Section 3465], and Accounting Guideline 19 - *Disclosures by Entities Subject to Rate Regulation.* These amended standards remove a temporary exemption in Handbook Section 1100 pertaining to the application of that section to the recognition and measurement of assets and liabilities arising from rate regulation, require the recognition of future income tax liabilities and assets in accordance with Handbook Section 3465. The revised standards are effective for the fiscal years beginning on or after January 1, 2009.

Following the removal of the temporary exemption for rate-regulated operations included in Handbook Section 1100, the Corporation developed accounting policies for its assets and liabilities arising from rate regulation using professional judgement. Upon final assessment and in accordance with Handbook Section 1100, the Corporation has determined that its assets and liabilities arising from rate-regulated activities qualify for recognition under Canadian GAAP. Accordingly, the removal of the temporary exemption had no effect on the Corporation's results from operations as of December 31, 2009.

The impact of the amendment to Handbook Section 3465 requires the recognition of future income tax assets and liabilities, applied on a retroactive basis without prior period restatement. The implementation of these standards did not impact the Corporation's earnings or cashflows. As at December 31, 2009, the Corporation has recorded a future tax asset of $6,200,000 and a future income tax liability of $2,375,000.

Goodwill and Intangible Assets

Effective January 1, 2009, the Corporation retrospectively adopted CICA Handbook Section 3064 - *Goodwill and Intangible Assets* [Handbook Section 3064]. Handbook Section 3064 replaces Handbook Section 3062 - *Goodwill and Other Intangible Assets* [Handbook Section 3062] and provides extensive guidance on recognition, measurement and disclosure of intangible assets.

The Corporation evaluated existing intangible assets as at January 1, 2009 to determine whether the intangible assets recognized under previous Handbook Section 3062 met the definition, recognition and measurement criteria of an intangible asset in accordance with Handbook Section 3064. The assets included computer software and capital contributions. The Corporation did not identify any expenditures that no longer met the definition of Intangible Assets under Handbook Section 3064.

As a result of adopting this new accounting standard, the Corporation has reclassified computer software previously classified as property, plant and equipment and capital contributions previously classified as other long-term assets, as intangible assets.

Financial Instruments

In January, 2009, the CICA issued Emerging Issues Committee Abstract 173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities* ["EIC-173"], effective for annual financial statements ending on or after January, 2009. EIC-173 provides further information on the determination of the fair value of financial assets and liabilities under Handbook Section 3855 - *Financial Instruments - Recognition and Measurement* [Handbook Section 3855]. It states that an entity's own credit and credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. The adoption of this standard did not have any impact on the Corporation's results of operations and financial position.

In June, 2009, the CICA amended Handbook Section 3862 to include additional disclosure requirements with respect to fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements.

The Corporation adopted these amendments effective for the fiscal year ended December 31, 2009. Comparative information is not required in the first year of application *[note 23].*

In August, 2009, the CICA amended Handbook Section 3855 to add guidance concerning the assessment of embedded derivatives upon reclassification of a financial asset out of the assets held-for-trading category. These amendments apply prospectively to reclassifications made on or after July 1, 2009. Earlier adoption is permitted. The application of these amendments did not have an impact on the Corporation's results of operations or financial position.

In August, 2009, the CICA amended Handbook Section 3025 - *Impaired Loans* to include held-to-maturity investments and to confirm the definition of a loan to that in amended Handbook Section 3855. These amendments apply to annual financial statements relating to fiscal years beginning on or after November 1, 2008. The Corporation adopted these amendments effective for the fiscal year ended December 31, 2009. The application of these amendments did not have any impact on the Corporation's results of operation or financial position.

Future Accounting Standards

International Financial Reporting Standards "IFRS"

On February 13, 2008, the AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for fiscal years beginning on or after January 1, 2011. Some of the converged standards will be implemented in Canada during the transition period with the remaining standards adopted at the change over date. The Corporation is in the process of developing an internal initiative to govern the conversion process and is currently in the process of evaluating the impact of the potential conversion to IFRS on the financial statements. At this time, the impact on the Corporation's future financial position and results of operations is not reasonably determinable or estimable.

Financial Instruments - Recognition and Measurement

In June, 2009, the CICA amended Handbook Section 3855 to clarify when an embedded prepayment option is separated from its host debt instrument for accounting purposes. This amendment applies to annual financial statements relating to fiscal years beginning on or after January 1, 2011. Earlier adoption is permitted. This Section has also been amended to clarify the application of the effective interest method after a debt instrument has been impaired. This amendment applies retrospectively to financial statements for fiscal years beginning on or after January 1, 2010. The Corporation expects these amendments will have no impact on its results of operations and financial position.

Comprehensive Revaluation of Assets and Liabilities

In August, 2009, the CICA amended Handbook Section 1625 - *Comprehensive Revaluation of Assets and Liabilities* to be consistent with Handbook Section 1582 - *Business Combinations*, Handbook Section 1601 and Handbook Section 1602, which were issued in January, 2009. The amendments apply prospectively to comprehensive revaluations of assets and liabilities occurring in fiscal years beginning on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year. The Corporation expects these amendments will have no impact on its results of operations and financial position.

3. DUE FROM ASSOCIATED COMPANIES

Balances due from associated companies bear interest at prime with no specific terms of repayment.

4. INTANGIBLE ASSETS

Details of year-end intangible assets balances are as follows:

	2009		2008	
	Cost	**Accumulated amortization**	Cost	Accumulated amortization
	$	$	$	$
Computer software	**765,366**	**708,157**	765,366	643,151
Capital contributions to Hydro One for wholesale meters	**894,171**	—	548,576	—
	1,659,537	**708,157**	1,313,942	643,151
Intangible assets, net	**951,380**		670,791	

See note 14 for details of amortization for the year.

5. REGULATORY ASSETS (LIABILITIES)

	2009 $	2008 $
Regulatory Assets		
Deferral for cash pension contributions	**474**	589,994
Deferral for OEB annual cost assessment	**121**	156,573
Recovery/Repayment of regulatory balances - 2009 OEB Approved	**—**	1,504
Deferral for IFRS implementation costs	**5,640**	—
	6,235	748,071
Retailer Cost Variance	**160,720**	433,666
Recovery/Repayment of regulatory balances - 2006 OEB Approved	**113,544**	147,511
Smart Meter deferral	**8,516,457**	—
Regulatory Assets	**8,796,956**	1,329,248
Regulatory Liabilities		
PILS deferral	**(1,635,123)**	(1,605,052)
Smart Meter deferral	**—**	(366,564)
Recovery/Repayment of regulatory balances - 2009 OEB Approved	**(1,595,971)**	—
	(3,231,094)	(1,971,616)
Wholesale market services	**(1,234,223)**	(2,924,176)
Network transmission services	**200,704**	(1,021,913)
Connection transmission charges	**1,904,684**	537,143
Commodity	**(1,673,179)**	(2,389,109)
Retail settlement variances	**(802,014)**	(5,798,055)
Regulatory Liabilities	**(4,033,108)**	(7,769,671)

In the absence of rate regulation, carrying charges on regulatory assets and liabilities in 2009 would have decreased by $67,115 [2008 - decreased by $154,807] (see Statement of Operations and Retained Earnings).

The regulatory asset and liability balances attract carrying charges at OEB prescribed rates and are defined as follows:

[a] Recovery/Repayment of regulatory balances

2006 OEB Approved

OEB approved balances of regulatory accounts as at December 31, 2004, including carrying charges on such balances to April 30, 2006, were transferred to this account for disposition. The net asset entry closing the asset and liability accounts amounted to $473,574. Distribution rate rider amounts are credited/debited to this account as are OEB prescribed carrying charges.

2009 OEB Approved

OEB approved balances of regulatory accounts as at December 31, 2007, including carrying charges on such balances to April 30, 2009, were transferred to this account for disposition. The net liability entry closing the asset and liability accounts amounted to $2,139,323. Distribution rate rider amounts are credited/debited to this account as are OEB prescribed carrying charges.

[b] Retail settlement variance accounts

These balances represent the variances between the flow-through amounts charged by the Corporation to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred since January 1, 2008, as balances to December 31, 2007 were closed to Recovery/Repayment of regulatory balance accounts.

The OEB reviews Retail Settlement Variances quarterly for commodity and annually for non-commodity, for dispositions.

[c] Retail cost variance accounts

As per the criteria in the Accounting Procedures Handbook, the Corporation defers the net costs of services relating to the supply of competitive electricity to retailer customers since January 1, 2008, as balances to December 31, 2007 were closed to Recovery/Repayment of regulatory balance accounts.

In the absence of rate regulation, expenses in 2009 would have been $49,087 higher [2008 - $105,220].

[d] Smart Meter deferrals

The OEB approved a smart meter rate adder of $1.95 [2008 - $0.30] per residential meter and has directed Local Distribution Companies (LDC's) to defer this seed funding along with costs incurred in implementing the government's smart meter initiative. Funding deferred in the current year amount to $854,052 [2008 - $160,396]. As at December 31, 2009, smart meter capital expenditures, net of accumulated depreciation, totalling $7,246,395 [2008 - $nil] have been recorded to a regulatory asset. These expenditures would otherwise have been recorded as property, plant and equipment and intangible assets under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $7,185,830 and $60,565 higher [2008 - $nil and $nil respectively].

For the year ended December 31, 2009, smart meter operating expenses of $241,508 [2008 - $41,269], and smart meter depreciation expense of $221,838 [2008 - $nil] were deferred which would have been expensed under Canadian GAAP for unregulated businesses.

The Corporation has deferred the loss on disposition for the applicable residential and small business meters which have been removed and replaced with smart meters. This stranded asset cost of $2,022,184 [2008 - $nil] would have been expensed under Canadian GAAP for unregulated businesses.

[e] Deferral account for cash pension contributions

The OEB allowed incremental OMERS pension expenditures for the fiscal years commencing January 1, 2005 and continuing until April 30, 2006 to be deferred. The balance to December 31, 2007, including carrying charges to April 30, 2009, was closed to Recovery/Repayment of regulatory balance accounts.

[f] Deferral account for OEB annual cost assessments

The OEB allowed incremental OEB annual cost assessments for the fiscal years 2004 and 2005. The balance to December 31, 2007, including carrying charges to April 30, 2009, was closed to Recovery/Repayment of regulatory balance accounts.

6. CORPORATE INCOME AND CAPITAL TAXES

The provision for payments in lieu of corporate income and capital taxes differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate.

The impact of differences between the Corporation's reported income tax expense on operating income and the expense that would otherwise result from the application of statutory rates is as follows:

	2009 $	2008 $
Earnings before provision for taxes	**1,566,930**	1,532,687
Statutory Canadian federal and provincial income tax rate (%)	**33.00**	33.50
Expected provision	**517,086**	513,450
Temporary differences		
Amortization and capital cost allowance	**67,780**	256,833
Amortization and eligible capital expenditure amortization	**(1,740)**	(1,900)
Regulatory asset (repayment) recovery	**203,519**	132,607
Other	**(52,645)**	62,010
Current tax provision	**734,000**	963,000
Effective tax rate (%)	**46.85**	62.83

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

	2009 $	2008 $
Property, plant and equipment and intangible assets	**21,400,000**	—
Post-employment benefits liability	**2,804,000**	—
Organization costs	**71,000**	—
Asset retirement obligation	**525,000**	—
Regulatory assets	**(9,300,000)**	—
Other taxable temporary differences	**(200,000)**	—
Net gross accounting/tax differences	**15,300,000**	—

Presented on the balance sheet as follows:

	2009 $	2008 $
Future income tax assets, long-term	**6,200,000**	—
Future income tax liabilities, long-term	**2,375,000**	—

Future taxes recoverable of $3,825,000 has been credited to the Statement of Operations to reflect the retroactive adjustment. Of this amount, $276,000 represents the current year provision and $3,549,000 represents the cumulative adjustments of years prior to 2009, the year of adoption.

7. PROPERTY, PLANT AND EQUIPMENT

[a] Details of year-end property, plant and equipment balances are as follows:

	2009		2008	
	Cost $	**Accumulated amortization** $	Cost $	Accumulated amortization $
Buildings	**3,932,881**	**1,646,339**	3,895,055	1,574,491
Distribution equipment	**123,186,487**	**62,055,300**	121,471,628	60,830,723
General office equipment	**3,954,136**	**3,639,025**	3,845,373	3,519,479
Land	**133,038**	**—**	133,038	—
Other equipment	**2,995,151**	**2,397,892**	2,787,446	2,302,296
Rolling stock	**5,456,943**	**3,812,153**	5,205,581	3,895,934
Transformation equipment	**8,614,850**	**5,644,193**	8,614,850	5,441,209
	148,273,486	**79,194,902**	145,952,971	77,564,132
Property, plant and equipment, net	**69,078,584**		68,388,839	

See note 14 for details of the amortization for the year.

[b] Details of year-end capital contributions balances are as follows:

	2009		2008	
	Capital contributions $	**Accumulated amortization** $	Capital contributions $	Accumulated amortization $
Distribution equipment	**10,244,703**	**1,929,700**	9,055,928	1,561,900
Capital contributions, net	**8,315,003**		7,494,028	

See note 14 for details of the amortization for the year.

8. LONG-TERM DEBT

Long-term debt consists of the following:

	2009	2008
	$	$
Bank term loan payable in monthly instalments of $64,400 including interest at 5.271% [nil% in 2008], maturing July, 2024.	**7,852,420**	—
Less amounts included in current liabilities	**367,673**	—
Long-term portion	**7,484,747**	—

Principal repayments required over the next five years and thereafter are as follows:

	$
2010	367,673
2011	387,529
2012	408,458
2013	430,516
2014	453,766
Thereafter	5,804,478
	7,852,420

As collateral for the above loan, the Corporation has provided:

A general security agreement representing a first charge on all assets and undertaking, including without limitation, equipment specific to the Smart Meter Program.

Smart meter loan proceeds of $8,000,000 were deposited into a separate bank account and drawn upon as spending occurred. As at December 31st, $412,474 remains in the separate account and is reported as restricted cash on the Statement of Cash Flows.

9. BANK CREDITS

[a] The Corporation has an operating loan available to them in the amount of $6,395,495 [2008 - $6,395,495] by way of prime rate based loans or bankers' acceptances. At year-end, $nil [2008 - $nil] was utilized. The prime rate based loans bear interest at bank prime. Prime at December 31, 2009 was 2.25% [2008 - 3.5%]. The bankers' acceptances bear a stamping fee at 0.5% per annum.

The operating loan has been secured.

[b] The Corporation has a letter of credit or stand-by letters of guarantee available to them in the amount of $9,708,637 [2008 - $9,708,637] of which $9,708,637 [2008 - $9,708,637] was issued at December 31, 2009. This credit will be used by the Corporation to assist in meeting its prudential obligations to the Independent Electricity System Operater ("IESO"). The credit bears interest at bank prime. Prime at December 31, 2009 was 2.25% [2008 - 3.5%]. Amounts payable to the IESO are recorded in current liabilities on the balance sheet.

10. EMPLOYEE FUTURE BENEFITS

The Corporation has a number of unfunded benefit plans providing retirement and post-employment benefits (excluding pension) to most of its employees.

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

	2009 $	2008 $
Accrued benefit obligation at January 1	**3,128,278**	3,037,599
Current service costs	**138,402**	142,446
Interest cost	**170,456**	161,357
Benefits paid in the year or moved to current liability	**(239,733)**	(213,124)
Accrued benefit obligation, end of year	**3,197,403**	3,128,278
Projected accrued benefit obligation at December 31, using a 6.0% [2008 - 5.25%] discount rate	**3,197,403**	3,128,278
Unamortized actuarial loss	**(393,479)**	(459,186)
Accrued benefit liability	**2,803,924**	2,669,092

The main actuarial assumptions employed for the valuations are as follows:

[a] General inflation

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0% in 2007 and thereafter.

[b] Interest (discount) rate

The obligation as at December 31, 2009, of the present value of future liabilities and the expense for the year, were determined using an annual discount rate of 6.0%.

[c] Salary levels

Future general salary and wage levels were assumed to increase at 3.3% per annum.

[d] Medical costs

Medical costs were assumed to increase at a rate of 5.8% in 2007, 9.0% in 2008 graded-down by 1% per annum leveling off at 5% in 2012 and thereafter.

11. NOTE PAYABLE TO THE CORPORATION OF THE CITY OF THUNDER BAY

The note is a non-interest bearing note payable to The Corporation of the City of Thunder Bay (sole shareholder of Thunder Bay Hydro Corporation, the Corporation's parent company). Principal repayment in the next twelve months is expected to be $nil.

	2009 $	2008 $
Note payable to The Corporation of the City of Thunder Bay	**33,490,500**	33,490,500

12. ASSET RETIREMENT OBLIGATION

A reconciliation between the opening and closing ARO liability balances is as follows:

	2009 $	2008 $
Balance, beginning of year	**512,186**	325,000
ARO liabilities incurred in the year	—	187,186
ARO liabilities settled in the year	—	—
Accretion expense	**12,933**	—
Balance, end of year	**525,119**	512,186

At December 31, 2009, the Corporation estimates the undiscounted amount of cash flows required over the next eleven years [2008 - twelve years] to settle the ARO is $701,480 [2008 - $701,480]. A discount rate of 6.0% was used to calculate the carrying value of the ARO liabilities. No assets have been restricted for settlement of the liability.

13. OTHER OPERATING REVENUE

	2009 $	2008 $
Pole line rentals	**452,058**	426,289
Competitive market revenues	**205,640**	204,677
Interest earned	**120,174**	479,071
Utility services	**341,750**	237,774
Reconnection and change in occupancy charges	**284,565**	289,210
Late payment charges	**289,447**	272,798
Sundry earnings	**286,230**	295,625
	1,979,864	2,205,444

14. AMORTIZATION

	2009 $	2008 $
Amortization of general plant	**4,874,755**	4,757,459
Amortization of capital contributions	**(367,800)**	(333,200)
Amortization of unallocated office and data processing equipment	**91,669**	135,667
	4,598,624	4,559,926
Amortization of other property, plant and equipment included in relevant expense categories in the Statement of Operations and Retained Earnings	**588,862**	584,998
	5,187,486	5,144,924
Amortization included in capitalized expenditures	**221,800**	222,402
Amortization of property, plant and equipment	**4,900,680**	4,809,969
Amortization of intangible assets	**65,006**	112,553
	5,187,486	5,144,924

15. PENSION PLAN

The Corporation's current service pension costs for the year ended December 31, 2009 were $635,756 [2008 - $590,644].

16. STATEMENT OF CASH FLOWS

[a] The net change in non-cash working capital balances related to operations consists of the following:

	2009 $	2008 $
Decrease (increase) in current assets		
Accounts receivable	**(613,408)**	63,256
Unbilled revenue	**(1,190,545)**	(257,351)
Payments in lieu of corporate income taxes receivable	**210,550**	163,814
Due from associated companies	**(509,559)**	(83,576)
Stores inventory	**(130,341)**	(19,086)
Prepaid expenses	**48,197**	7,087
	(2,185,106)	(125,856)
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	**764,568**	2,029,354
Debt retirement charges payable	**(15,243)**	30,254
Deferred revenue and contributions	**4,998**	(24,461)
Customer deposits	**406,563**	(41,710)
	1,160,886	1,993,437
	(1,024,220)	1,867,581

[b] During the year, property, plant and equipment were acquired at an aggregate cost of $8,516,759 [2008 - $7,822,358], of which $807,148 [2008 - $1,095,130] was funded by cash contributions, $381,627 [2008 - $330,774] was funded by contributions in-kind, $119,293 [2008 - $187,186] was funded by long-term liability, $221,800 [2008 - $222,402] was funded by capitalized amortization, and $6,986,891 [2008 - $5,986,866] was funded by cash.

[c] During the year, assets acquired relating to the Smart Meter Initiative amounted to $7,468,233 [2008 - $nil], all of which $7,468,233 [2008 - $nil] was funded by long-term debt.

[d] Cash outflows (inflows) during the year for interest and income taxes were as follows:

	2009 $	2008 $
Interest received	**(10,282)**	(16,862)
Income taxes paid	**1,026,412**	955,824

17. REBATES

During the year, the Corporation received $361,129 [2008 - $876,909] from the IESO in connection with the Ontario Power Generation ("OPG") Rebate. Of the OPG Rebate, $218,661 was allocated to customers. The remaining $142,468 was forwarded to various electricity retailers.

18. RELATED PARTY TRANSACTIONS

The Corporation of the City of Thunder Bay
The Corporation provides certain services to The Corporation of the City of Thunder Bay (the Corporation's parent's shareholder) in the normal course of business at commercial rates.

For the year ended December 31, 2009, pole rental revenue from The Corporation of the City of Thunder Bay in the amount of $308,430 [2008 - $305,748] and other sundry revenues in the amount of $38,947 [2008 - $31,748] were recorded. The Corporation of the City of Thunder Bay also contributed towards capital construction during the year in the amount of $70,461 [2008 - $104,240]. Included in "Accounts receivable" is $10,931 [2008 - $48,295] receivable from The Corporation of the City of Thunder Bay related to these other activities.

For the year ended December 31, 2009, the Corporation billed electricity revenues in the amount of $9,087,224 [2008 - $8,229,620] to The Corporation of the City of Thunder Bay. At December 31, 2009, included in "Accounts receivable" is $541,968 [2008 - $471,915] receivable from The Corporation of the City of Thunder Bay, related to this electricity revenue.

The Corporation purchases certain services from The Corporation of the City of Thunder Bay in the normal course of business at commercial rates. For the year ended December 31, 2009, the Corporation was charged rent of $307,438 [2008 - $293,474], telecommunication costs of $274,788 [2008 - $206,183], water billings of $8,639 [2008 - $8,388], and property taxes of $138,357 [2008 - $143,045].

Associated Companies [note 3]
The Corporation managed and administered the rental water heater operations for Thunder Bay Hydro Energy Services Inc. (TBHESI) until September, 2008. Administration services were provided to the purchaser during the transition period which ended April 30, 2009. During 2009, the Corporation charged TBHESI $47,442 [2008 - $139,577] for direct costs and administration fees.

The Corporation provides services to Thunder Bay Hydro Utility Services Inc. (TBHUSI) at cost plus the higher of bank prime and the Corporation's approved rate of return of 3.75%, effective May 1, 2009 [2.93% previously]. During 2009, the Corporation charged TBHUSI $165,797 [2008 - $98,196] for direct costs and administration fees.

The Corporation provides services to Thunder Bay Renewable Power Incorporation (TBRPI) at cost plus a 10% administrative charge. During 2009, the Corporation charged TBRPI $128,511 [2008 - $nil] for direct costs and administration fees. Included in Customer Deposits is $544,864 [2008 - $nil] related to required OPA directed deposits for TBRPI Landfill Gas Project.

The Corporation also charged interest at bank prime on outstanding advances from TBRPI. Interest charged during 2009 was $10,776 [2008 - $nil].

19. CONTINGENCIES

[a] Griffith et al. v. Toronto Hydro-Electric Commission et al.

This action has been brought under the Class Proceedings Act, 1992. The Plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro and to other Ontario municipal electric utilities (LDCs) who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the Criminal Code. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of a similar proceeding brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

In 2007, Enbridge filed an application to the OEB to recover the Court-approved amount and related amounts from ratepayers. On February 4, 2008, the OEB approved recovery of the said amounts from ratepayers over a five-year period.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the Plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. The parties are in settlement discussions. A contingent settlement is currently being negotiated. If the settlement is approved, the Corporation's liability will be $161,000.

[b] Ministry of Finance Audit

The Ministry of Finance has conducted an audit of the Corporation's Payments in Lieu of Taxes (PILS) filings for the years 2001 and 2002. Certain filing positions taken by the Corporation with respect to the treatment of some regulatory assets/liabilities were challenged and resulted in the Ministry of Finance issuing Notices of Reassessments for each of the 2001 to 2004 fiscal years. The reassessments resulted in additional PILS payable of $1,128,844 plus interest of $174,696 which have been recorded as part of the Payments in lieu of corporate income taxes receivable balance. The Corporation has filed a Notice of Objection to the reassessments. If the Objection is denied, the Corporation will recognize the reassessed taxes in the year of denial. If the settlement is approved, the Corporation's liability will be $161,000.

20. FINANCIAL INSTRUMENTS

[a] Fair value

The Corporation's cash and cash equivalents, investments, accounts receivable, accounts payable and accrued liabilities, and customer deposits carrying values approximate fair value due to the short maturity of these investments.

Amounts due from associated companies are recognized in accordance with CICA 3840, Related Party Transactions. There is no requirement to fair value the amounts on initial recognition.

The fair market value of the long-term debt approximates its carrying value.

[b] Risk factors

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

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

Credit risk

Financial instruments are exposed to credit risk as a result of the risk of the counter-party defaulting on its obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The Corporation provides reserves for credit risks based on the financial condition and short and long-term exposures to counter-parties.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from the Corporation's customers. The Corporation has approximately 49,360 customers, the majority of which are residential. The Corporation collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2009, the Corporation held security deposits in the amount of $1,842,697 [2008 - $1,980,998].

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 and Retained Earnings. Subsequent recoveries of receivables previously provisioned are credited to the Statement of Operations and Retained Earnings.

Credit risk associated with accounts receivable is as follows:

	2009	2008
	$	$
Total accounts receivable	**7,683,997**	7,362,967
Less: Allowance for doubtful accounts	**(383,419)**	(675,797)
Total accounts receivable, net	**7,300,578**	6,687,170
Of which		
Outstanding for less than 30 days	**5,779,512**	5,629,802
Outstanding for more than 31 days but not more than 180 days	**1,236,127**	1,244,763
Outstanding for more than 181 days	**318,956**	351,266
Amounts unbilled	**349,402**	137,136
Less: Allowance for doubtful accounts	**(383,419)**	(675,797)
Total accounts receivable, net	**7,300,578**	6,687,170

Unbilled revenue represents amounts to which the Corporation has a contractual right to receive cash through future billings but are unbilled at year-end. As at December 31, 2009, total unbilled revenue is $12,347,110 [2008 - $11,156,565]. Unbilled revenue outstanding is considered current.

At December 31, 2009, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk

The Corporation is exposed to interest rate risk in holding certain financial instruments. The Corporation's objective is to minimize net interest expense. Under the Corporation's Revolving Credit Facility, the Corporation may obtain short-term borrowings for working capital purposes. These borrowings expose the Corporation to fluctuations in short-term interest rate [borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit]. The fee payable for bankers' acceptances and letters of credit is based on 0.5% fee per annum plus stamping fee when applicable.

Cash balances that are not required to meet day-to-day obligations of the Corporation are periodically invested in short-term Canadian money market instruments, exposing the Corporation to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by the Corporation.

Liquidity risk

The Corporation monitors and manages 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 is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to credit facilities and monitors cash balances regularly to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risks associated with financial commitments are as follows:

	December 31, 2009		
	Due within 1 year $	**Due between 1 year and 5 years** $	**Due after 5 years** $
Financial liabilities			
Accounts payable and accrued liabilities	**11,967,879**	—	—
Note payable to The Corporation of the City of Thunder Bay	—	—	33,490,500
Long-term debt	**367,673**	1,680,269	5,804,478

Hedging and derivatives risk

As at December 31, 2009, and December 31, 2008, the Corporation has not entered into hedging and derivative financial instruments.

Foreign exchange risk

As at December 31, 2009, the Corporation has limited exposure to the changing values of foreign currencies. While the Corporation purchases good and services which are payable in U.S. dollars, and purchases U.S. currency to meet the related payables commitments when required, the impact of these transactions is not material to the financial statements.

21. LIABILITY INSURANCE

The Corporation belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2009, the Corporation has not been made aware of any assessments for losses.

22. CAPITAL DISCLOSURES

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

- ensure ongoing access to funding in order to maintain and improve the electricity distribution system of the Corporation;
- ensure compliance with covenants related to its credit facilities and the note payable to The Corporation of the City of Thunder Bay ("City Note");
- begin to align its capital structure for regulated activities of the Corporation with the debt to equity structure recommended by the OEB.

As of December 31, 2009, the Corporation's definition of capital includes shareholder's equity and long-term debt and has remained unchanged from December 31, 2008. As of December 31, 2009, shareholder's equity amounts to $44,664,909 [2008 - $40,006,979] and long-term debt amounts to $41,342,920 [2008 - $33,490,500]. The Corporation's long-term capital structure at December 31, 2009 is 52% debt and 48% equity [2008 - 48% debt and 52% equity]. There have been no changes in the Corporation's approach to capital management during the year.

As at December 31, 2009, the Corporation is subject to debt agreements that contain various covenants. The Corporation is governed by the Shareholder Declaration which limits future borrowings, liens, and provisions of security without prior written consent. The Corporation is also subject to a Subordination Agreement with respect to the $33,490,550 promissory note given to The Corporation of the City of Thunder Bay, with said Subordination Agreement providing for no acceleration rights, as approved by the Bank's legal department.

The Corporation's revolving credit facility limits the debt to capitalization ratio to a maximum of 60% [2008 - 50%] and a debt service coverage ratio of not less than 1.20:1 [2008 - a minimum interest coverage ratio (ICR) of 2X]. As at December 31, 2009, the debt to capitalization ratio was 18% [2008 - 15%] and debt service coverage was 3.39:1 [2008 - 54,328X]. The Corporation's long-term debt agreements also include positive and negative covenants such as limitations on funded indebtedness, capital expenditures restrictions on mergers, amalgamations or consolidations, and limitations on providing security or guarantees to any third party. As at December 31, 2009, the Corporation was in compliance with the financial covenants included in its long-term debt agreements, City Note and short-term revolving credit facility.

23. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2009 financial statements.

Thunder Bay Hydro Electricity Distribution Inc.
Schedule - Expenses

Year ended December 31	**2009**	2008
	$	$
OPERATIONS AND MAINTENANCE		
Customer premises/meters and devices	**368,476**	715,165
Distribution	**3,886,951**	3,542,307
Safety and training	**406,227**	367,381
System control/station maintenance	**1,438,500**	1,377,341
Transformer	**631,040**	493,269
Total operations and maintenance expenses	**6,731,194**	6,495,463
ADMINISTRATION		
Bad debts	**110,203**	90,978
Billing and collecting	**896,973**	868,093
Customer information service	**1,089,466**	1,189,496
Information services	**759,107**	690,414
Meter reading	**251,155**	289,097
Total customer - related admininstration expenses	**3,106,904**	3,128,078
General		
Corporate	**623,347**	645,356
Directors' expenses	**61,830**	66,138
Finance	**783,002**	773,684
Human resources	**286,893**	298,739
President's office	**483,607**	364,939
Power systems administration	**299,066**	286,751
Total general administration expenses	**2,537,745**	2,435,607
Total administration expenses	**5,644,649**	5,563,685
TOTAL EXPENSES	**12,375,843**	12,059,148

Grant Thornton

Financial Statements

Thunder Bay Hydro Electricity Distribution Inc.

December 31, 2010

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Grant Thornton

Independent Auditor's Report

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To the Shareholder of

Thunder Bay Hydro Electricity Distribution Inc.

We have audited the accompanying financial statements of Thunder Bay Hydro Electricity Distribution Inc., which comprise the balance sheet as at December 31, 2010, and the statements of operations and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

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

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers 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.

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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 Thunder Bay Hydro Electricity Distribution Inc. as at December 31, 2010, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Grant Thornton LLP

Thunder Bay, Canada
April 13, 2011

Chartered Accountants
Licensed Public Accountants

Thunder Bay Hydro Electricity Distribution Inc.
Balance Sheet

As at December 31	2010	2009
	$	$
		[restated - note 23]
ASSETS		
Current		
Cash and cash equivalents	**8,514,481**	9,375,065
Investments	**45,651**	—
Accounts receivable *[note 20]*	**6,954,250**	7,006,217
Unbilled revenue *[note 20]*	**11,589,843**	12,347,110
Payments in lieu of corporate income taxes receivable	**1,576,218**	1,392,997
Due from affiliated companies *[note 3]*	**189,831**	803,659
Stores inventory	**1,270,878**	1,571,869
Prepaid expenses	**205,085**	199,595
Other taxes receivable	**777,005**	294,361
Total current assets	**31,123,242**	32,990,873
Other		
Intangible assets *[note 4]*	**1,278,115**	951,380
Regulatory assets *[note 5]*	**8,202,090**	8,588,044
Future income tax assets *[note 6]*	**6,603,500**	6,552,000
Total other assets	**16,083,705**	16,091,424
Property, plant and equipment, at cost		
Property, plant and equipment, net *[note 7[a]]*	**72,049,593**	69,078,584
Capital contributions, net *[note 7[b]]*	**(10,305,020)**	(8,315,003)
Construction-in-progress	**1,758,058**	1,276,696
Property, plant and equipment, net	**63,502,631**	62,040,277
	110,709,578	111,122,574

See accompanying notes to the financial statements.

On behalf of the Board:

Director

Director

Grant Thornton

	2010	2009
	$	$ *[restated - note 23]*
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	**12,718,478**	11,967,880
Debt retirement charges payable	**533,626**	546,426
Deferred revenue and contributions	**182,080**	332,639
Customer deposits	**3,059,521**	2,387,561
Current portion of long-term debt *[note 8]*	**387,529**	367,673
Total current liabilities	**16,881,234**	15,602,179
Long-term		
Regulatory liabilities *[note 5]*	**2,874,839**	4,033,108
Employee future benefits liability *[note 10]*	**2,858,140**	2,803,924
Note payable to The Corporation of the City of Thunder Bay *[note 11]*	**33,490,500**	33,490,500
Asset retirement obligation *[note 12]*	**118,118**	525,119
Long-term debt *[note 8]*	**7,097,218**	7,484,747
Future income tax liabilities *[note 6]*	**2,040,000**	2,315,000
Total long-term liabilities	**48,478,815**	50,652,398
Shareholder's equity		
Share capital		
Authorized		
Unlimited common shares		
Issued		
1,000 common shares	**34,931,625**	34,931,625
Retained earnings	**10,417,904**	9,936,372
Total shareholder's equity	**45,349,529**	44,867,997
	110,709,578	111,122,574

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Operations and Retained Earnings

Year ended December 31	2010	2009
	$	$ *[restated - note 23]*
REVENUES AND FLOW-THROUGH CHARGES		
Flow-through charges plus distribution revenues	**95,171,784**	91,153,222
Flow-through costs of energy	**(78,674,166)**	(74,346,574)
Distribution revenue	**16,497,618**	16,806,648
Other operating revenue *[note 13]*	**1,965,980**	1,979,864
	18,463,598	18,786,512
EXPENSES		
Administration *[schedule]*	**5,730,821**	5,644,649
Amortization *[note 14]*	**4,582,337**	4,598,624
Operations and maintenance *[schedule]*	**6,996,631**	6,731,194
Provision for payments in lieu of capital tax	**60,000**	178,000
	17,369,789	17,152,467
Earnings before the following	**1,093,809**	1,634,045
Interest on long-term debt	**403,510**	208,912
Carrying charges on regulatory assets/liabilities, net	**(44,733)**	67,115
Earnings before provision for taxes	**735,032**	1,358,018
Payments in lieu of corporate income taxes *[note 6]*		
Current	**580,000**	734,000
Future taxes recoverable	**(326,500)**	(4,237,000)
	253,500	(3,503,000)
Earnings for year	**481,532**	4,861,018
Retained earnings, beginning of year as previously reported	**9,733,284**	5,075,354
Restatement *[note 23]*	**203,088**	—
Retained earnings, end of year	**10,417,904**	9,936,372

See accompanying notes to the financial statements.

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Cash Flows

Year ended December 31	**2010**	2009
	$	$
		[restated - note 23]
OPERATING ACTIVITIES		
Earnings for year	**481,532**	4,861,018
Add charges (deduct credits) to operations not involving a current payment (receipt) of cash		
Accretion (recovery) expense related to asset retirement obligation	**(9,063)**	12,933
Amortization of property, plant and equipment *[note 14]*	**4,897,483**	4,900,680
Amortization of intangible assets *[note 14]*	**65,561**	65,006
Increase in employee future benefits	**54,216**	134,832
Gain on disposal of property, plant and equipment	**(400)**	(14,640)
Future taxes recoverable	**(326,500)**	(4,237,000)
	5,162,829	5,722,829
Net change in non-cash working capital balances related to operations *[note 16[a]]*	**2,311,897**	(1,024,220)
Cash provided by operating activities	**7,474,726**	4,698,609
INVESTMENT ACTIVITIES		
Proceeds on sale of property, plant and equipment	**400**	14,640
Additions to intangible assets	**(392,296)**	(345,595)
Additions to property, plant and equipment, net *[note 16[b]]*	**(6,931,681)**	(6,986,891)
Sale (purchase) of investments	**(45,651)**	5,014,176
Cash used in investment activities	**(7,369,228)**	(2,303,670)
FINANCING ACTIVITIES		
Decrease in regulatory assets *[note 16[c]]*	**798,428**	209,437
Decrease in regulatory liabilities	**(1,158,269)**	(3,736,563)
Repayments of bank loan	**(367,673)**	(147,580)
Unapplied loan proceeds - restricted cash	**(412,474)**	412,474
Non-cash stranded asset cost included in regulatory assets	**221,401**	2,022,184
ARO liabilities settled during the year	**(47,495)**	—
Cash used in financing activities	**(966,082)**	(1,240,048)
Increase (decrease) in cash and cash equivalents during year	**(860,584)**	1,154,891
Cash and cash equivalents, beginning of year	**9,375,065**	8,220,174
Cash and cash equivalents, end of year	**8,514,481**	9,375,065
Represented by		
Cash - unrestricted	**8,514,481**	8,962,591
Cash - restricted	**—**	412,474
	8,514,481	9,375,065

See accompanying notes to the financial statements.

GENERAL

Thunder Bay Hydro Electricity Distribution Inc. ("the Corporation") is a wholly-owned subsidiary company of Thunder Bay Hydro Corporation, providing electrical distribution services to the inhabitants of The Corporation of the City of Thunder Bay and the Fort William First Nation Reserve, as regulated by the Ontario Energy Board ("OEB").

1. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and reflect the significant accounting policies summarized below.

Rate setting and regulation

The rates of the Corporation's electricity distribution are subject to regulation by the OEB. The cost of power and all costs other than distribution related to the operations of the electricity grid including transmission, connection and administration costs are flowed through to the consumer.

The distribution revenue is designed to recover the costs incurred by the Corporation in delivering electricity to customers. Distribution rates are regulated by the OEB and typically comprise a monthly service charge and a volumetric charge.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and in banks.

Stores inventory

Stores inventory consists principally of maintenance and construction materials and is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

Property, plant and equipment

Property, plant and equipment are stated at cost less accumulated amortization. In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation or amortization, with no gain or loss reflected in results of operations. Gains or losses on retirement or disposition of assets which are not grouped are credited or charged to other operating revenue. Amortization is provided on a straight-line basis for property, plant and equipment over their estimated service lives at the following annual rates:

Buildings	2%
Distribution and transformation equipment	3% to 4%
Other assets	10% to 20%
Rolling stock	12½% to 20%

As necessary, these assets are tested for impairment.

Intangible assets

Intangible assets represent computer applications software and capital contributions. These assets are carried at cost net of accumulated amortization.

Amortization is provided on a straight-line basis for intangible assets over their estimated useful lives at the following rates:

Computer software	20%
Capital contributions	4%

Pension plan

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 *[note 15]*. The Corporation recognizes the expense related to this plan as contributions are made.

Other post-employment benefits

Employee future benefits provided by the Corporation include medical and life insurance benefits and accumulated sick leave credits. These plans provide benefits to certain employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render the services. Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. Actuarial gains (losses) are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in earnings in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in earnings for the period in which a settlement occurs.

Revenue recognition

Distribution revenue is recognized on the basis of regular meter readings. Estimates of customer usage since the last meter reading date, to the end of the year are recorded as unbilled revenue.

Pole line revenue is recognized based on annual contracted rates and agreed-upon pole counts.

The Corporation has entered into Conservation Demand Management ("CDM") agreements with the Ontario Power Authority ("OPA") for the period from 2007 to 2010. Performance, management and incentive fees are recognized as the related CDM programs are delivered.

Revenues from Lost Revenue Adjustment Mechanism and Shared Savings Mechanism approved in rates are recognized on a accrual basis.

Other revenue is recognized when the requirements as to performance for transactions involving the sale of goods or services are met and ultimate collection is reasonably assured at the time of performance.

Construction-in-progress

Construction-in-progress is comprised of the costs of assets not yet placed into service, assets under construction, and pre-construction activities related to projects expected to be completed. These amounts are not amortized. Upon energization of assets the amounts are transferred to property, plant and equipment and are amortized on a straight-line basis over the expected service life of the asset.

Contributions in aid of construction

Capital contributions are required contributions received from outside sources, used to finance additions to property, plant and equipment. Capital contributions are credited against property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related property, plant and equipment.

Customer deposits

Customers' advance deposits are cash collections from customers or Energy Retailers to guarantee the payment of energy-related bills. The deposits bear interest at prime less 2% and is paid annually to customers.

Customer deposits also include collections from renewable generation customers for connection cost and capacity allocation deposits, as dictated by the OPA and contributions in aid of construction on construction projects which have not been completed or capitalized during the year. Interest may be payable on the capacity allocation deposit upon connection of the renewable generation facility. Interest is not payable on contributions in aid of construction.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from those estimates.

Corporate income and capital taxes

The current tax-exempt status of the Corporation's parent company under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) reflects the fact that the Corporation's parent company is wholly-owned by a municipality. This tax-exempt status might be lost in a number of circumstances, including if the municipality ceases to own 90% or more of the shares or capital of the Corporation's parent company, or if a non-government entity has rights immediately or in the future, either absolutely or contingently, to acquire more than 10% of the shares of the Corporation's parent company.

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing income taxes and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Current income taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at amounts receivable or payable from/to the OEFC.

Future income taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

Asset retirement obligation

The Corporation recognizes a liability for the future removal and handling cost for contamination in distribution equipment and units in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is amortized and the liability is adjusted annually for the discount applied upon initial recognition of the liability ("accretion expense") and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ("ARO") is incurred and when the fair value is determined.

Financial instruments

On initial recognition, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between willing parties.

The Corporation classifies its financial instruments as follows and uses the following methods and assumption to estimate the fair value of each class of financial instruments for which carrying amounts are included in the Balance Sheet:

- Cash is classified as "Held-for-Trading" and is measured at fair value.
- Investments comprising short-term investments, are classified as "Held-for-Trading" and are measured at fair value.
- Accounts receivable are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Due from affiliated companies are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Customers' advance deposits are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity.

- Note payable to The Corporation of the City of Thunder Bay is classified as "Other Financial Liabilities". It was originally recognized in accordance with CICA 3840, *Related Party Transactions*, being the amount of consideration established by contract. There is no requirement to fair value the amount on initial recognition because of the non-market rate of interest. Subsequent measurements are determined in accordance with CICA 3840 which provides the basis for subsequent measurement at amortized cost. The only changes to the amount initially recognized are changes in principal balances.

- Long-term debt is classified as "Other Financial Liabilities" and was initially measured at cost. Subsequent measurements are recorded at amortized cost using the effective interest method.

2. ACCOUNTING CHANGES

Future Accounting Standards

Comprehensive Revaluation of Assets and Liabilities

In August, 2009, the CICA amended Handbook Section 1625 - *Comprehensive Revaluation of Assets and Liabilities* to be consistent with Handbook Section 1582 - *Business Combinations*, Handbook Section 1601 and Handbook Section 1602, which were issued in January, 2009. The amendments apply prospectively to comprehensive revaluations of assets and liabilities occurring in fiscal years beginning on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year. The Corporation expects these amendments will have no impact on its results of operations and financial position.

3. DUE FROM AFFILIATED COMPANIES

Balances due from affiliated companies bear interest at prime and are due on demand.

4. INTANGIBLE ASSETS

Details of year-end intangible assets balances are as follows:

	2010		2009	
	Cost	**Accumulated amortization**	Cost	Accumulated amortization
	$	$	$	$
Computer software	**779,512**	**738,478**	765,366	708,157
Capital contributions to Hydro One for wholesale meters	**1,272,321**	**35,240**	894,171	—
	2,051,833	**773,718**	1,659,537	708,157
Intangible assets, net	**1,278,115**		951,380	

See note 14 for details of amortization for the year.

5. REGULATORY ASSETS (LIABILITIES)

	2010 $	2009 $ *[restated - note 23]*
Regulatory Assets		
Deferral for cash pension contributions	**474**	474
Deferral for OEB annual cost assessment	**121**	121
Special Purpose Charge	**165,588**	—
Deferral for IFRS implementation costs	**8,301**	5,640
	174,484	6,235
Retailer Cost Variance	**211,621**	160,720
Recovery/repayment of regulatory balances - 2006 OEB Approved	**—**	113,544
Smart Meter deferral	**7,815,985**	8,307,545
Regulatory Assets	**8,202,090**	8,588,044
Regulatory Liabilities		
PILS deferral	**(1,646,222)**	(1,635,123)
Recovery/repayment of regulatory balances	**(627,139)**	(1,595,971)
	(2,273,361)	(3,231,094)
Wholesale market services	**(1,643,018)**	(1,234,223)
Network transmission services	**629,612**	200,704
Connection transmission charges	**798,937**	1,904,684
Commodity	**(387,009)**	(1,673,179)
Retail settlement variances	**(601,478)**	(802,014)
Regulatory Liabilities	**(2,874,839)**	(4,033,108)

In the absence of rate regulation, carrying charges on regulatory assets and liabilities in 2010 would have increased by $44,733 [2009 - decreased by $67,115] (see Statement of Operations and Retained Earnings).

The regulatory asset and liability balances attract carrying charges at OEB prescribed rates and are defined as follows:

[a] Recovery/Repayment of regulatory balances

2010 OEB Approved

OEB approved balances of regulatory accounts as at December 31, 2008, including carrying charges on such balances to April 30, 2010, which were transferred to this account for disposition. The net liability entry closing the asset and liability accounts amounted to $1,025,804. Distribution rate rider amounts are credited/debited to this account as are OEB prescribed carrying charges.

2009 OEB Approved

OEB approved balances of regulatory accounts as at December 31, 2007, including carrying charges on such balances to April 30, 2009, were transferred to this account for disposition. The net liability entry closing the asset and liability accounts amounted to $2,139,323. Distribution rate rider amounts are credited/debited to this account as are OEB prescribed carrying charges.

[b] Retail settlement variance accounts

These balances represent the variances between the flow-through amounts charged by the Corporation to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred since January 1, 2009, as balances to December 31, 2008 were closed to Recovery/Repayment of regulatory balance accounts.

The OEB reviews Retail Settlement Variances quarterly for commodity and annually for non-commodity, for dispositions.

[c] Retail cost variance accounts

As per the criteria in the Accounting Procedures Handbook, the Corporation defers the net costs of services relating to the supply of competitive electricity to retailer customers since January 1, 2008, as balances to December 31, 2007 were closed to Recovery/Repayment of regulatory balance accounts.

In the absence of rate regulation, expenses in 2010 would have been $49,451 higher [2009 - $49,087].

[d] Smart Meter deferrals

The OEB approved a smart meter rate adder of $1.97 [2009 - $1.95] per meter and has directed Local Distribution Companies ("LDC's") to defer this seed funding along with costs incurred in implementing the government's smart meter initiative. Funding deferred in the current year amount to $1,153,223 [2009 - $854,052]. As at December 31, 2010, smart meter capital expenditures, net of accumulated depreciation, totalling $7,166,274 [2009 - $7,246,395] have been recorded to a regulatory asset. These expenditures would otherwise have been recorded as property, plant and equipment and intangible assets under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $6,992,051 and $174,223 higher [2009 - $7,185,830 and $60,565 respectively].

For the year ended December 31, 2010, smart meter operating expenses of $196,573 [2009 - $22,597], and smart meter depreciation expense of $502,784 [2009 - $221,838] were deferred which would have been expensed under Canadian GAAP for unregulated businesses.

The Corporation has deferred the loss on disposition for the applicable residential and small business meters which have been removed and replaced with smart meters. This stranded asset cost of $221,401 [2009 - $2,022,184] would have been expensed under Canadian GAAP for unregulated businesses. The stranded asset cost and distribution revenue have been reduced by the amount of funding in current rates for depreciation on these assets in the amount of $238,814.

[e] Special Purpose Charge

This balance represents the amount remitted to the Ministry of Finance for the Corporation's Special Purpose Charge Assessment amount net of the amounts recovered from customers on account of the assessment. Carrying charges are calculated on the monthly opening balance at the OEB prescribed interest rate.

In the absence of rate regulation, revenues would have been increased by $223,631 and expenses would have increased by $389,219.

[f] Deferral of International Financial Reporting Standards (" IFRS") Implementation Costs

The OEB has approved a deferral account to record one-time administrative incremental IFRS transition costs, which are not already recovered in distribution rates.

In the absence of rate regulation, expenses would have been $8,301 higher [2009 - $5,604].

6. CORPORATE INCOME AND CAPITAL TAXES

The provision for payments in lieu of corporate income and capital taxes differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate.

The impact of differences between the Corporation's reported income tax expense on operating income and the expense that would otherwise result from the application of statutory rates is as follows:

	2010 $	2009 $
		[restated - note 23]
Earnings before provision for taxes	**735,032**	1,358,018
Statutory Canadian federal and provincial income tax rate (%)	**31.00**	33.00
Expected provision	**227,860**	448,146
Apprenticeship tax credit	**(102,630)**	(77,070)
Permanent differences	**46,488**	35,402
Rate adjustments	**81,782**	117,500
Cumulative adjustments of years prior to 2009	**—**	(4,026,978)
Current tax provision	**253,500**	(3,503,000)
Effective tax rate (%)	**34.49**	(2.58)

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

	2010 $	2009 $
Property, plant and equipment and intangible assets	**109,448**	(46,369)
Regulatory assets	**(446,426)**	(312,169)
Other taxable temporary differences	**10,478**	(8,646)
Cumulative adjustments of years prior to 2009	**—**	(3,869,816)
	(326,500)	(4,237,000)

Presented on the balance sheet as follows:

	2010 $	2009 $
Future income tax assets, long-term	**6,603,500**	6,552,000
Future income tax liabilities, long-term	**2,040,000**	2,315,000

7. PROPERTY, PLANT AND EQUIPMENT

[a] Details of year-end property, plant and equipment balances are as follows:

	2010		2009	
	Cost	**Accumulated amortization**	Cost	Accumulated amortization
	$	$	$	$
Buildings	**3,932,881**	**1,718,400**	3,932,881	1,646,339
Distribution equipment	**130,541,300**	**66,639,769**	123,186,487	62,055,300
General office equipment	**4,042,815**	**3,700,717**	3,954,136	3,639,025
Land	**133,038**	**—**	133,038	—
Other equipment	**3,143,135**	**2,504,603**	2,995,151	2,397,892
Rolling stock	**6,219,429**	**4,191,352**	5,456,943	3,812,153
Transformation equipment	**8,639,193**	**5,847,357**	8,614,850	5,644,193
	156,651,791	**84,602,198**	148,273,486	79,194,902
Property, plant and equipment, net	**72,049,593**		69,078,584	

See note 14 for details of the amortization for the year.

[b] Details of year-end capital contributions balances are as follows:

	2010		2009	
	Capital contributions	**Accumulated amortization**	Capital contributions	Accumulated amortization
	$	$	$	$
Distribution equipment	**12,744,352**	**2,439,332**	10,244,703	1,929,700
Capital contributions, net	**10,305,020**		8,315,003	

See note 14 for details of the amortization for the year.

8. LONG-TERM DEBT

Long-term debt consists of the following:

	2010 $	2009 $
Bank term loan payable in monthly instalments of $64,400 including interest at 5.27%, maturing July, 2024.	**7,484,747**	7,852,420
Less amounts included in current liabilities	**387,529**	367,673
Long-term portion	**7,097,218**	7,484,747

Principal repayments required over the next five years and thereafter are as follows:

	$
2011	387,529
2012	408,458
2013	430,516
2014	453,766
2015	478,272
Thereafter	5,326,206
	7,484,747

As collateral for the above loan, the Corporation has provided a general security agreement representing a first charge on all assets and undertaking, including without limitation, equipment specific to the Smart Meter Program.

9. BANK CREDITS

[a] The Corporation has an operating loan available in the amount of $6,395,495 [2009 - $6,395,495] by way of prime rate based loans or bankers' acceptances. At year-end, $nil [2009 - $nil] was utilized. The prime rate based loans bear interest at bank prime. Prime at December 31, 2010 was 3.0% [2009 - 2.25%]. The bankers' acceptances bear a stamping fee at 0.5% per annum.

The operating loan is secured by:

[i] Guarantee of Advance, unlimited, as executed by Thunder Bay Hydro Corporation; and
[ii] Subordination Agreement with respect to the $33,490,550 promissory note given to the City of Thunder Bay, with said Subordination Agreement providing for no acceleration rights, as approved by the Bank's legal department.

[b] The Corporation has a letter of credit or stand-by letters of guarantee available in the amount of $9,708,637 [2009 - $9,708,637] of which $9,708,637 [2009 - $9,708,637] was issued at December 31, 2010. This credit will be used by the Corporation to assist in meeting its prudential obligations to the Independent Electricity System Operator ("IESO"). The credit bears interest at bank prime. Prime at December 31, 2010 was 3.0% [2009 - 2.25%]. Amounts payable to the IESO are recorded in current liabilities on the balance sheet.

10. EMPLOYEE FUTURE BENEFITS

The Corporation has a number of unfunded benefit plans providing retirement and post-employment benefits (excluding pension) to most of its employees.

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

	2010 $	2009 $
Accrued benefit obligation at January 1	**3,011,388**	3,128,278
Actuarial gains	**(310,067)**	(186,015)
Current service costs	**108,777**	138,402
Interest cost	**141,953**	170,456
Benefits paid in the year or moved to current liability	**(212,474)**	(239,733)
Accrued benefit obligation, end of year	**2,739,577**	3,011,388
Projected accrued benefit obligation at December 31, using a 5.25% [2009 - 6.0%] discount rate	**2,739,577**	3,011,388
Unamortized actuarial gain (loss)	**118,563**	(207,464)
Accrued benefit liability	**2,858,140**	2,803,924

The main actuarial assumptions employed for the valuations are as follows:

[a] General inflation

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0%.

[b] Interest (discount) rate

The obligation as at December 31, 2010, of the present value of future liabilities and the expense for the year, were determined using an annual discount rate of 5.25%.

[c] Salary levels

Future general salary and wage levels were assumed to increase at 3.3% per annum.

[d] Medical costs

Medical costs were assumed to increase at a rate of 8.0% in 2010, 7.63% in 2011 graded-down by .37% per annum leveling off at 5% in 2018 and thereafter.

11. NOTE PAYABLE TO THE CORPORATION OF THE CITY OF THUNDER BAY

The note is a non-interest bearing note payable to The Corporation of the City of Thunder Bay (sole shareholder of Thunder Bay Hydro Corporation, the Corporation's parent company). Principal repayment in the next twelve months is expected to be $nil.

	2010 $	2009 $
Note payable to The Corporation of the City of Thunder Bay	**33,490,500**	33,490,500

12. ASSET RETIREMENT OBLIGATION

A reconciliation between the opening and closing ARO liability balances is as follows:

	2010 $	2009 $
Balance, beginning of year	**525,119**	512,186
Adjustment for change in estimates	**(350,443)**	—
ARO liabilities settled in the year	**(47,495)**	—
Accretion (recovery) expense	**(9,063)**	12,933
Balance, end of year	**118,118**	525,119

At December 31, 2010, the Corporation estimates the undiscounted amount of cash flows required over the ten years [2009 - eleven years] to settle the ARO is $195,136 [2009 - $701,480]. A discount rate of 5.25% [2009 - 6.00%] was used to calculate the carrying value of the ARO liabilities. No assets have been restricted for settlement of the liability.

13. OTHER OPERATING REVENUE *[note 18]*

	2010 $	2009 $
Pole line rentals	**454,382**	452,058
Competitive market revenues	**200,237**	205,640
Interest earned	**101,164**	120,174
Utility services	**317,095**	341,750
Reconnection and change in occupancy charges	**269,676**	284,565
Late payment charges	**261,868**	289,447
Sundry earnings	**361,558**	286,230
	1,965,980	1,979,864

14. AMORTIZATION

	2010 $	2009 $
Amortization of general plant	**5,037,156**	4,874,755
Amortization of capital contributions	**(509,632)**	(367,800)
Amortization of unallocated office and data processing equipment	**54,813**	91,669
	4,582,337	4,598,624
Amortization of other property, plant and equipment included in relevant expense categories in the Statement of Operations and Retained Earnings	**639,369**	588,862
	5,221,706	5,187,486
Amortization included in capitalized expenditures	**258,662**	221,800
Amortization of property, plant and equipment	**4,897,483**	4,900,680
Amortization of intangible assets	**65,561**	65,006
	5,221,706	5,187,486

15. PENSION PLAN

The Corporation's current service pension costs for the year ended December 31, 2010 were $659,310 [2009 - $635,756].

16. STATEMENT OF CASH FLOWS

[a] The net change in non-cash working capital balances related to operations consists of the following:

	2010 $	2009 $
Decrease (increase) in current assets		
Accounts receivable	**51,967**	(644,981)
Unbilled revenue	**757,267**	(1,190,545)
Payments in lieu of corporate income taxes receivable	**(183,221)**	210,550
Due from affiliated companies	**613,828**	(509,559)
Stores inventory	**300,991**	(130,341)
Prepaid expenses	**(5,490)**	48,197
Other taxes receivable	**(482,644)**	31,573
	1,052,698	(2,185,106)
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	**750,598**	764,568
Debt retirement charges payable	**(12,800)**	(15,243)
Deferred revenue and contributions	**(150,559)**	4,998
Customer deposits	**671,960**	406,563
	1,259,199	1,160,886
	2,311,897	(1,024,220)

[b] During the year, property, plant and equipment were acquired at an aggregate cost of $9,689,992 [2009 - $8,516,759], of which $1,839,888 [2009 - $807,148] was funded by cash contributions, $659,761 [2009 - $381,627] was funded by contributions in-kind, $nil [2009 - $119,293] was funded by long-term liability, $258,662 [2009 - $221,800] was funded by capitalized amortization, and $6,931,691 [2009 - $6,986,891] was funded by cash.

[c] During the year, assets acquired relating to the Smart Meter Initiative amounted to $422,663 [2009 - $7,468,233], of which $412,474 [2009 - $7,468,233] was funded by long-term debt, and $10,189 [2009 - $nil] was funded by cash.

[d] Cash outflows (inflows) during the year for interest and income taxes were as follows:

	2010 $	2009 $
Interest paid (received)	**816**	(10,282)
Income taxes paid	**916,644**	1,026,412

17. REBATES

During the year, the Corporation received $nil [2009 - $361,129] from the IESO in connection with the Ontario Power Generation ("OPG") Rebate.

18. RELATED PARTY TRANSACTIONS

The Corporation of the City of Thunder Bay

The Corporation provides certain services to The Corporation of the City of Thunder Bay (the Corporation's parent's shareholder) in the normal course of business at commercial rates.

For the year ended December 31, 2010, pole rental revenue from The Corporation of the City of Thunder Bay in the amount of $310,263 [2009 - $308,430] and other sundry revenues in the amount of $36,543 [2009 - $38,947] were recorded. The Corporation of the City of Thunder Bay also contributed towards capital construction during the year in the amount of $335,889 [2009 - $70,461]. Included in "Accounts receivable" is $10,625 [2009 - $10,931] receivable from The Corporation of the City of Thunder Bay related to these other activities.

For the year ended December 31, 2010, the Corporation billed electricity revenues in the amount of $9,191,485 [2009 - $9,087,224] to The Corporation of the City of Thunder Bay. At December 31, 2010, included in "Accounts receivable" is $299,644 [2009 - $541,968] receivable from The Corporation of the City of Thunder Bay, related to this electricity revenue.

The Corporation purchases certain services from The Corporation of the City of Thunder Bay in the normal course of business at commercial rates. For the year ended December 31, 2010, the Corporation was charged rent of $302,036 [2009 - $307,438], telecommunication capital and operating costs of $361,792 [2009 - $274,788], water billings of $8,133 [2009 - $8,639], and property taxes of $126,987 [2009 - $138,357].

Affiliated Companies (Common Shareholder) [note 3]

The Corporation provides services to Thunder Bay Hydro Utility Services Inc. ("TBHUSI") at cost plus the higher of bank prime and the Corporation's approved rate of return of 3.75%, effective May 1, 2009 [2.93% previously]. During 2010, the Corporation charged TBHUSI $231,877 [2009 - $165,797] for direct costs and administration fees.

The Corporation provides services to Thunder Bay Hydro Renewable Power Incorporated ("TBHRPI") for cost plus an annual administrative charge of $7,500 (10% administrative charge on costs in 2009). During 2010, the Corporation charged TBRPI $86,750 [2009 - $128,511] for direct costs and administration fees. Included in Customer Deposits is $nil [2009 - $544,864] related to required OPA directed deposits for TBRPI Landfill Gas Project.

The Corporation also charged interest at bank prime on outstanding advances from TBRPI. Interest charged during 2010 was $4,817 [2009 - $10,776].

19. CONTINGENCIES

Ministry of Finance Audit

The Ministry of Finance has conducted an audit of the Corporation's Payments in Lieu of Taxes (PILS) filings for the years 2001 and 2002. Certain filing positions taken by the Corporation with respect to the treatment of some regulatory assets/liabilities were challenged and resulted in the Ministry of Finance issuing Notices of Reassessments for each of the 2001 to 2004 fiscal years. The reassessments resulted in additional PILS payable of $1,128,844 plus interest of $174,696 which have been recorded as part of the Payments in lieu of corporate income taxes receivable balance. The Corporation has filed a Notice of Objection to the reassessments. If the Objection is denied, the Corporation will recognize the reassessed taxes in the year of denial.

20. FINANCIAL INSTRUMENTS

[a] Fair value

The Corporation's cash and cash equivalents, investments, accounts receivable, accounts payable and accrued liabilities, and customer deposits carrying values approximate fair value due to the short maturity of these balances.

Amounts due from affiliated companies are recognized in accordance with CICA Handbook Section 3840, Related Party Transactions. There is no requirement to fair value the amounts on initial recognition.

The fair market value of the long-term debt approximates its carrying value.

[b] Risk factors

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

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

Credit risk

Financial instruments are exposed to credit risk as a result of the risk of the counter-party defaulting on its obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The Corporation provides reserves for credit risks based on the financial condition and short and long-term exposures to counter-parties.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from the Corporation's customers. The Corporation has approximately 49,600 customers, the majority of which are residential. The Corporation collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2010, the Corporation held security deposits in the amount of $1,862,140 [2009 - $1,842,697].

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 and Retained Earnings. Subsequent recoveries of receivables previously provisioned are credited to the Statement of Operations and Retained Earnings.

Credit risk associated with accounts receivable is as follows:

	2010 $	2009 $
Total accounts receivable	**7,341,273**	7,389,636
Less: Allowance for doubtful accounts	**(387,023)**	(383,419)
Total accounts receivable, net	**6,954,250**	7,006,217
Of which		
Outstanding for less than 30 days	**5,753,364**	5,485,151
Outstanding for more than 31 days but not more than 180 days	**1,199,581**	1,236,127
Outstanding for more than 181 days	**333,957**	318,956
Amounts unbilled	**54,371**	349,402
Less: Allowance for doubtful accounts	**(387,023)**	(383,419)
Total accounts receivable, net	**6,954,250**	7,006,217

Unbilled revenue represents amounts to which the Corporation has a contractual right to receive cash through future billings but are unbilled at year-end. As at December 31, 2010, total unbilled revenue is $11,589,843 [2009 - $12,347,110]. Unbilled revenue outstanding is considered current.

At December 31, 2010, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk

The Corporation is exposed to interest rate risk in holding certain financial instruments. The Corporation's objective is to minimize net interest expense. Under the Corporation's Revolving Credit Facility, the Corporation may obtain short-term borrowings for working capital purposes. These borrowings expose the Corporation to fluctuations in short-term interest rate [borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit]. The fee payable for bankers' acceptances and letters of credit is based on 0.5% fee per annum plus stamping fee when applicable.

Cash balances that are not required to meet day-to-day obligations of the Corporation are periodically invested in short-term Canadian money market instruments, exposing the Corporation to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by the Corporation.

Liquidity risk

The Corporation monitors and manages 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 is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to credit facilities and monitors cash balances regularly to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risks associated with financial commitments are as follows:

	December 31, 2010		
	Due within 1 year $	Due between 1 year and 5 years $	Due after 5 years $
Financial liabilities			
Accounts payable and accrued liabilities	**12,718,478**	—	—
Note payable to The Corporation of the City of Thunder Bay	—	—	**33,490,500**
Long-term debt	**387,529**	**1,771,012**	**5,326,206**

Foreign exchange risk

As at December 31, 2010, the Corporation has limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in U.S. dollars, and purchases U.S. currency to meet the related payables commitments when required, the impact of these transactions is not material to the financial statements.

21. LIABILITY INSURANCE

The Corporation belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2010, the Corporation has not been made aware of any assessments for losses.

22. CAPITAL DISCLOSURES

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

- ensure ongoing access to funding in order to maintain and improve the electricity distribution system of the Corporation;
- ensure compliance with covenants related to its credit facilities and the note payable to The Corporation of the City of Thunder Bay ("City Note");
- begin to align its capital structure for regulated activities of the Corporation with the debt to equity structure recommended by the OEB.

As of December 31, 2010, the Corporation's definition of capital includes shareholder's equity and long-term debt and has remained unchanged from December 31, 2009. As of December 31, 2010, shareholder's equity amounts to $45,349,529 [2009 - $44,867,997] and long-term debt amounts to $40,975,247 [2009 - $41,342,920]. The Corporation's long-term capital structure at December 31, 2010 is 47% debt and 53% equity [2009 - 52% debt and 48% equity]. There have been no changes in the Corporation's approach to capital management during the year.

As at December 31, 2010, the Corporation is subject to debt agreements that contain various covenants. The Corporation is governed by the Shareholder Declaration which limits future borrowings, liens, and provisions of security without prior written consent. The Corporation is also subject to a Subordination Agreement with respect to the $33,490,550 promissory note given to The Corporation of the City of Thunder Bay, with said Subordination Agreement providing for no acceleration rights, as approved by the Bank's legal department.

The Corporation's revolving credit facility limits the debt to capitalization ratio to a maximum of 60% [2009 - 60%] and a debt service coverage ratio of not less than 1.20:1 [2009 - 1.20:1]. As at December 31, 2010, the debt to capitalization ratio was 17% [2009 - 18%] and debt service coverage was 5.3:1 [2009 - 3.39:1]. The Corporation's long-term debt agreements also include positive and negative covenants such as limitations on funded indebtedness, capital expenditures restrictions on mergers, amalgamations or consolidations, and limitations on providing security or guarantees to any third party. As at December 31, 2010, the Corporation was in compliance with the financial covenants included in its long-term debt agreements, City Note and short-term revolving credit facility.

23. RESTATEMENT

An error in the treatment of the interest related to the smart meter long-term debt was corrected as a prior period adjustment. This presentation change was a result of presentation clarification received from the OEB in December 2010. As a result regulatory assets decreased $208,912, interest on long-term debt increased and prior period earnings decreased by $208,912 and the provision for future taxes recoverable increased $52,225.

The 2009 comparative figures have also been restated to reflect a correction in the calculation of future taxes. The future income tax assets increased $352,000, the future income tax liabilities decreased $112,225 and the provision for future taxes recoverable increased $359,775.

The cumulative effects of these restatements has been to increase the opening retained earnings by $203,088.

Thunder Bay Hydro Electricity Distribution Inc.
Schedule - Expenses

Year ended December 31	**2010**	2009
	$	$
OPERATIONS AND MAINTENANCE *[note 18]*		
Customer premises/meters and devices	**312,909**	368,476
Distribution	**4,053,585**	3,886,951
Safety and training	**434,553**	406,227
System control/station maintenance	**1,567,393**	1,438,500
Transformer	**628,191**	631,040
Total operations and maintenance expenses	**6,996,631**	6,731,194
ADMINISTRATION *[note 18]*		
Bad debts	**31,790**	110,203
Billing and collecting	**1,112,638**	896,973
Customer information service	**1,078,791**	1,089,466
Information services	**790,542**	759,107
Meter reading	**164,601**	251,155
Total customer - related administration expenses	**3,178,362**	3,106,904
General *[note 18]*		
Corporate	**498,974**	623,347
Directors' expenses	**62,398**	61,830
Finance	**784,247**	783,002
Human resources	**345,472**	286,893
President's office	**349,069**	364,200
Power systems administration	**297,617**	299,066
Renewable generation activities	**214,682**	119,407
Total general administration expenses	**2,552,459**	2,537,745
Total administration expenses	**5,730,821**	5,644,649
TOTAL EXPENSES	**12,727,452**	12,375,843

Financial Statements

Thunder Bay Hydro Electricity Distribution Inc.

December 31, 2011

Thunder Bay Hydro Electricity Distribution Inc.

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BDO Canada LLP
1095 Barton Street
Thunder Bay ON P7B 5N3 Canada

Independent Auditor's Report

To the Shareholder of
Thunder Bay Hydro Electricity Distribution Inc.

We have audited the accompanying financial statements of Thunder Bay Hydro Electricity Distribution Inc., which comprise the balance sheet as at December 31, 2011, and the statements of operations and retained earnings and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

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

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers 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 presentation of the financial statements.

We believe that the audit evidence we have obtained in our audit 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 Thunder Bay 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.

BDO Canada LLP, a Canadian limited liability partnership, is a member of BDO International Limited, a UK company limited by guarantee, and forms part of the international BDO network of independent member firms.

BDO

Independent Auditor's Report (cont'd)

Other Matters
The financial statements of Thunder Bay Hydro Electricity Distribution Inc. for the year ended December 31, 2010, were reported on under an unqualified independent auditor's report dated April 13, 2011 by another public accounting firm.

BDO Canada LLP

Chartered Accountants, Licensed Public Accountants

Thunder Bay, Ontario
April 26, 2012

Thunder Bay Hydro Electricity Distribution Inc.
Balance Sheet

As at December 31	**2011**	2010
	$	$
ASSETS		
Current		
Cash	**7,451,627**	8,514,481
Investments	**32,025**	45,651
Accounts receivable *[note 16]*	**9,271,498**	7,731,255
Unbilled revenue *[note 16]*	**13,517,342**	11,589,843
Payments in lieu of corporate income taxes receivable	**33,465**	1,576,218
Due from related parties *[note 15]*	**73,970**	189,831
Stores inventory	**1,310,812**	1,270,878
Prepaid expenses	**290,987**	205,085
Total current assets	**31,981,726**	31,123,242
Other		
Intangible assets *[note 2]*	**1,246,715**	1,278,115
Regulatory assets *[note 3]*	**8,303,200**	8,202,090
Future income tax assets *[note 4]*	**6,397,615**	6,603,500
Total other assets	**15,947,530**	16,083,705
Property, plant and equipment, at cost		
Property, plant and equipment, net *[note 5[a]]*	**76,041,529**	72,049,593
Capital contributions, net *[note 5[b]]*	**(12,634,977)**	(10,305,020)
Construction-in-progress	**3,002,923**	1,758,058
Property, plant and equipment, net	**66,409,475**	63,502,631
	114,338,731	110,709,578

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

On behalf of the Board:

Director Director

	2011	2010
	$	$
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	**13,105,494**	12,718,478
Debt retirement charges payable	**504,235**	533,626
Deferred revenue and contributions	**620,352**	182,080
Due to related party *[note 15]*	**112,173**	-
Customer deposits	**2,261,858**	3,059,521
Current portion of long-term debt *[note 6]*	**408,458**	387,529
Total current liabilities	**17,012,570**	16,881,234
Long-term		
Regulatory liabilities *[note 3]*	**5,091,445**	2,874,839
Employee future benefits liability *[note 8]*	**2,792,159**	2,858,140
Note payable to The Corporation of the City of Thunder Bay *[note 9]*	**33,490,500**	33,490,500
Asset retirement obligation *[note 10]*	**91,160**	118,118
Long-term debt *[note 6]*	**6,691,862**	7,097,218
Future income tax liabilities *[note 4]*	**1,789,115**	2,040,000
Total long-term liabilities	**49,946,241**	48,478,815
Shareholder's equity		
Share capital		
Authorized		
Unlimited common shares		
Issued		
1,000 common shares	**34,931,625**	34,931,625
Retained earnings	**12,448,295**	10,417,904
Total shareholder's equity	**47,379,920**	45,349,529
	114,338,731	110,709,578

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Operations and Retained Earnings

Year ended December 31	2011	2010
	$	$
REVENUES AND FLOW-THROUGH CHARGES		
Flow-through charges plus distribution revenues	**103,377,657**	95,171,784
Flow-through costs of energy	**(85,875,693)**	(78,674,166)
Distribution revenue	**17,501,964**	16,497,618
Other operating revenue *[note 11]*	**2,359,899**	1,965,980
	19,861,863	18,463,598
EXPENSES		
Administration *[schedule]*	**5,610,613**	5,730,821
Amortization *[note 12]*	**4,668,110**	4,582,337
Operations and maintenance *[schedule]*	**6,762,305**	6,996,631
Provision for payments in lieu of capital tax	**3,752**	60,000
	17,044,780	17,369,789
Earnings before the following	**2,817,083**	1,093,809
Interest on long-term debt	**386,668**	403,510
Carrying charges on regulatory assets/liabilities, net	**(261,851)**	(44,733)
Earnings before provision for taxes	**2,692,266**	735,032
Payments in lieu of corporate income taxes *[note 4]*		
Current	**706,875**	580,000
Future	**(45,000)**	(326,500)
	661,875	253,500
Earnings for year	**2,030,391**	481,532
Retained earnings, beginning of year	**10,417,904**	9,936,372
Retained earnings, end of year	**12,448,295**	10,417,904

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

Thunder Bay Hydro Electricity Distribution Inc.
Statement of Cash Flows

Year ended December 31	2011	2010
	$	$
OPERATING ACTIVITIES		
Earnings for year	**2,030,391**	481,532
Add charges (deduct credits) to operations not involving a current payment (receipt) of cash		
Accretion (recovery) expense related to asset retirement obligation	**5,119**	(9,063)
Amortization of capital contributions *[note 12]*	**(628,096)**	(509,632)
Amortization of property, plant and equipment *[note 12]*	**5,589,274**	5,407,115
Amortization of intangible assets *[note 12]*	**71,717**	65,561
(Decrease)Increase in employee future benefits	**(65,981)**	54,216
Gain on disposal of property, plant and equipment	**(25,451)**	(400)
Future income taxes	**(45,000)**	(326,500)
	6,931,973	5,162,829
Net change in non-cash working capital balances related to operations *[note 14[a]]*	**(1,824,557)**	2,311,897
Cash provided by operating activities	**5,107,416**	7,474,726
INVESTMENT ACTIVITIES		
Proceeds on sale of property, plant and equipment	**27,075**	400
Additions to intangible assets	**(40,317)**	(392,296)
Additions to property, plant and equipment, net *[note 14[b]]*	**(7,869,646)**	(6,931,681)
Sale (purchase) of investments	**13,626**	(45,651)
Cash used in investment activities	**(7,869,262)**	(7,369,228)
FINANCING ACTIVITIES		
(Increase)decrease in regulatory assets	**(101,110)**	798,428
Increase(decrease) in regulatory liabilities	**2,216,606**	(1,158,269)
Repayments of bank loan	**(384,427)**	(367,673)
Unapplied loan proceeds - restricted cash	**-**	(412,474)
Non-cash stranded asset cost included in regulatory assets	**-**	221,401
ARO liabilities settled during the year	**(32,077)**	(47,495)
Cash provided by (used in) financing activities	**1,698,992**	(966,082)
Decrease in cash during year	**(1,062,854)**	(860,584)
Cash, beginning of year	**8,514,481**	9,375,065
Cash , end of year	**7,451,627**	8,514,481

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

GENERAL

Thunder Bay Hydro Electricity Distribution Inc. ("the Corporation") is a wholly-owned subsidiary company of Thunder Bay Hydro Corporation, providing electrical distribution services to the inhabitants of The Corporation of the City of Thunder Bay and the Fort William First Nation Reserve, as regulated by the Ontario Energy Board ("OEB").

1. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and reflect the significant accounting policies summarized below.

International Financial Reporting Standards

The Corporation did not adopt IFRS for the year ended December 31, 2011 as the mandatory adoption for entities with activities subject to rate regulation was deferred to fiscal years beginning on or after January 1, 2012. The Accounting Standards has recently decided that the mandatory adoption of IFRS for such entities will be deferred an additional year. The Corporation is still considering its options and has not yet decided whether it will adopt IFRS in 2012 or 2013.

Rate setting and regulation

The rates of the Corporation's electricity distribution are subject to regulation by the OEB. The cost of power and all costs other than distribution related to the operations of the electricity grid including transmission, connection and administration costs are flowed through to the consumer.

The distribution revenue is designed to recover the costs incurred by the Corporation in delivering electricity to customers. Distribution rates are regulated by the OEB and typically comprise a monthly service charge and a volumetric charge.

Stores inventory

Stores inventory consists principally of maintenance and construction materials and is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

Property, plant and equipment

Property, plant and equipment are stated at cost less accumulated amortization. Gains or losses on retirement or disposition of assets which are not grouped are credited or charged to other operating revenue. Amortization is provided on a straight-line basis for property, plant and equipment over their estimated service lives at the following annual rates:

Buildings	2%
Distribution and transformation equipment	3% to 4%
Other assets	10% to 20%
Rolling stock	12½% to 20%

Spare Transformers and Meters

Spare transformers and meters are held to back up plant in service and are expected to substitute for original distribution plant transformers and meters when these original plant assets are being repaired. According to the criteria prescribed by the OEB in the Accounting Procedures Handbook the spare transformers and meters are treated as property, plant and equipment. Under Canadian GAAP for unregulated businesses the spare transformers and meters would be treated as inventory.

Intangible assets

Intangible assets represent computer applications software and capital contributions. These assets are carried at cost net of accumulated amortization.

Amortization is provided on a straight-line basis for intangible assets over their estimated useful lives at the following rates:

Computer software	20%
Capital contributions	4%

Regulated Assets and Liabilities

The company has adopted the CICA's Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". Based on OEB regulations, certain costs and variance account balances are recorded as regulatory liabilities and are reflected in the balance sheet until the OEB determines the manner and timing of their disposition.

Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior period(s), that are expected to be recovered from consumers in future periods through the rate-setting process. Regulatory liabilities represent future expenses associated with the collection of certain revenues, earned in the current period or in prior period(s), that are expected to be returned to consumers in future periods through the rate-setting process. Regulatory assets and liabilities can arise from differences in amounts collected from customers (based on regulated rates) and the corresponding costs of non-competitive electricity service incurred by the Corporation in the wholesale market administered by the Independent Electricity System Operator (the "IESO") after May 1, 2002.

These amounts have been accumulated pursuant to regulation underlying the Electricity Act (the "EA") and deferred in anticipation of their future recovery or expense in electricity distribution service charges. In the absence of rate regulation, these rate regulated assets and liabilities would be recognized in income in the period to which they relate. See Note 3 for further details.

Pension plan

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 *[note 13]*. The Corporation recognizes the expense related to this plan as contributions are made.

Other post-employment benefits

Employee future benefits provided by the Corporation include medical and life insurance benefits and accumulated sick leave credits. These plans provide benefits to certain employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render the services. Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. Actuarial gains (losses) are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in earnings in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in earnings for the period in which a settlement occurs.

Revenue recognition

Distribution revenue is recognized on the basis of regular meter readings. Estimates of customer usage since the last meter reading date, to the end of the year are recorded as unbilled revenue.

Pole line revenue is recognized based on annual contracted rates and agreed-upon pole counts.

The Corporation has entered into Conservation Demand Management ("CDM") agreements with the Ontario Power Authority ("OPA") for the period from 2011 to 2015. Performance, management and incentive fees are recognized according to the applicable OPA service agreements.

Revenues from Lost Revenue Adjustment Mechanism and Shared Savings Mechanism approved in rates are recognized on a accrual basis.

Other revenue is recognized when the requirements as to performance for transactions involving the sale of goods or services are met and ultimate collection is reasonably assured at the time of performance.

Construction-in-progress

Construction-in-progress is comprised of the costs of assets not yet placed into service, assets under construction, and pre-construction activities related to projects expected to be completed. These amounts are not amortized. Upon energization of assets the amounts are transferred to property, plant and equipment and are amortized on a straight-line basis over the expected service life of the asset.

Contributions in aid of construction

Capital contributions are required contributions received from outside sources, used to finance additions to property, plant and equipment. Capital contributions are credited against property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related property, plant and equipment.

Customer deposits

Customers' advance deposits are cash collections from customers or Energy Retailers to guarantee the payment of energy-related bills. The deposits bear interest at prime less 2% and is paid annually to customers.

Customer deposits also include collections from renewable generation customers for connection cost and capacity allocation deposits, as dictated by the OPA and contributions in aid of construction on construction projects which have not been completed or capitalized during the year. Interest may be payable on the capacity allocation deposit upon connection of the renewable generation facility. Interest is not payable on contributions in aid of construction.

Use of estimates and measurement uncertainty

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes as well as the disclosure of contingent assets and liabilities at the financial statement date.

Accounts receivable, unbilled service revenue, regulatory assets, regulatory liabilities and employee future benefits are reported based on amounts expected to be recovered or incurred and reflect an appropriate allowance for unrecoverable amounts based on management's estimates. Amounts recorded for amortization of property, plant and equipment are based on estimates of useful service life.

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

Corporate income and capital taxes

The current tax-exempt status of the Corporation's parent company under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) reflects the fact that the Corporation's parent company is wholly-owned by a municipality. This tax-exempt status might be lost in a number of circumstances, including if the municipality ceases to own 90% or more of the shares or capital of the Corporation's parent company, or if a non-government entity has rights immediately or in the future, either absolutely or contingently,

to acquire more than 10% of the shares of the Corporation's parent company.

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing income taxes and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Current income taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at amounts receivable or payable from/to the OEFC.

Future income taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they will be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

Asset retirement obligation

The Corporation recognizes a liability for the future removal and handling cost for contamination in distribution equipment and units in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is amortized and the liability is adjusted annually for the discount applied upon initial recognition of the liability ("accretion expense") and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ("ARO") is incurred and when the fair value is determined.

Financial instruments

On initial recognition, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between willing parties.

The Corporation classifies its financial instruments as follows and uses the following methods and assumptions to estimate the fair value of each class of financial instruments for which carrying amounts are included in the Balance Sheet:

- Cash is classified as "Held-for-Trading" and is measured at fair value.
- Investments comprising short-term investments, are classified as "Held-for-Trading" and are measured at fair value.
- Accounts receivable are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Due to/from related parties are classified as "Loans and Receivables" and are measured at amortized cost, which, upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Customer deposits are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity.

- Note payable to The Corporation of the City of Thunder Bay is classified as "Other Financial Liabilities" and are initially measured at cost.

- Long-term debt is classified as "Other Financial Liabilities" and was initially measured at cost. Subsequent measurements are recorded at amortized cost using the effective interest method.

2. INTANGIBLE ASSETS

Details of year-end intangible asset balances are as follows:

	2011		2010	
	Cost	**Accumulated amortization**	Cost	Accumulated amortization
	$	$	$	$
Computer software	**819,829**	**759,302**	779,512	738,478
Capital contributions to Hydro One for wholesale meters	**1,272,321**	**86,133**	1,272,321	35,240
	2,092,150	**845,435**	2,051,833	773,718
Intangible assets, net	**1,246,715**		1,278,115	

See note 12 for details of amortization for the year.

3. REGULATORY ASSETS (LIABILITIES)

	2011 $	2010 $
Regulatory Assets		
Deferral for cash pension contributions	**474**	474
Deferral for OEB annual cost assessment	**121**	121
Special Purpose Charge	**34,581**	165,588
Deferral for IFRS implementation costs	**51,295**	8,301
Recovery/repayment of regulatory balances	**864,030**	-
	950,501	174,484
Retailer Cost Variance	**281,283**	211,621
Smart Meter deferral	**7,071,416**	7,815,985
Regulatory Assets	**8,303,200**	8,202,090
Regulatory Liabilities		
PILS deferral	**(706,546)**	(1,646,222)
Recovery/repayment of regulatory balances	**-**	(627,139)
	(706,546)	(2,273,361)
Wholesale market services	**(2,521,861)**	(1,643,018)
Network transmission services	**(114,563)**	629,612
Connection transmission charges	**(412,480)**	798,937
Commodity	**(1,335,995)**	(387,009)
Retail settlement variances	**(4,384,899)**	(601,478)
Regulatory Liabilities	**(5,091,445)**	(2,874,839)

In the absence of rate regulation, carrying charges on regulatory assets and liabilities in 2011 would have increased by $261,851 [2010 - increased by $44,733] (see Statement of Operations and Retained Earnings).

The regulatory asset and liability balances attract carrying charges at OEB prescribed rates and are defined as follows:

[a] Recovery/Repayment of regulatory balances

2011 OEB Approved

OEB approved balances of regulatory accounts as at December 31, 2009, including carrying charges on such balances to April 30, 2011, which were transferred to this account for disposition. The net asset entry closing the asset and liability accounts amounted to $2,725,159. Distribution rate rider amounts are credited/debited to this account as are OEB prescribed carrying charges,

[b] Retail settlement variance accounts

These balances represent the variances between the flow-through amounts charged by the Corporation to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred since January 1, 2009, as balances to December 31, 2008 were closed to Recovery/Repayment of regulatory balance accounts.

The OEB reviews Retail Settlement Variances quarterly for commodity and annually for non-commodity, for dispositions.

[c] Retail cost variance accounts

As per the criteria in the Accounting Procedures Handbook, the Corporation defers the net costs of services relating to the supply of competitive electricity to retailer customers since January 1, 2008, as balances to December 31, 2007 were closed to Recovery/Repayment of regulatory balance accounts.

In the absence of rate regulation, expenses in 2011 would have been $66,164 higher [2010 - $49,451].

[d] Smart Meter deferrals

The OEB approved a Smart Meter rate adder of $1.97 [2010 - $1.97] per meter and has directed Local Distribution Companies ("LDC's") to defer this seed funding along with costs incurred in implementing the government's Smart Meter Initiative. Funding deferred in the current year amount to $1,170,991 [2010 - $1,153,223]. As at December 31, 2011, Smart Meter capital expenditures, net of accumulated depreciation, totalling $6,816,013 [2010 - $7,166,274] have been recorded to a regulatory asset. These expenditures would otherwise have been recorded as property, plant and equipment and intangible assets under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $6,732,577 and $153,436 higher [2010 - $6,992,051 and $174,223 respectively].

For the year ended December 31, 2011, Smart Meter operating expenses of $328,973 [2010 - $196,573], and Smart Meter depreciation expense of $521,005 [2010 - $502,784] were deferred which would have been expensed under Canadian GAAP for unregulated businesses.

The Corporation has deferred the loss on disposition for the applicable residential and small business meters which have been removed and replaced with Smart Meters. This stranded asset cost of $nil [2010 - $221,401] would have been expensed under Canadian GAAP for unregulated businesses. The stranded asset cost and distribution revenue have been reduced by the amount of funding in current rates for depreciation on these assets in the amount of $226,017.

[e] Special Purpose Charge

This balance represents the amount remitted to the Ministry of Finance for the Corporation's Special Purpose Charge Assessment amount net of the amounts recovered from customers on account of the assessment. Carrying charges are calculated on the monthly opening balance at the OEB prescribed interest rate.

In the absence of rate regulation, revenues would have been increased by $172,690 [2010 - $223,631] and expenses would have increased by $nil [2010 - $389,289].

[f] Deferral of International Financial Reporting Standards (" IFRS") Implementation Costs

The OEB has approved a deferral account to record one-time administrative incremental IFRS transition costs, which are not already recovered in distribution rates.

In the absence of rate regulation, expenses would have been $42,993 higher [2010 - $8,301].

[g] Payment in Lieu of Taxes ("PIL's")

On November 28, 2008, the OEB commenced a combined proceeding to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes ("PILs") for the period October 1, 2001 to April 30, 2006. A

decision was issued June 24, 2011 which included direction to all other distributors. "Each remaining distributor will be expected to apply for final disposition of account 1562 with its next general rates application (either IRM or cost of service). If the distributor files evidence in accordance with all the various decisions made in the course of this proceeding, including the use of the updated model of referenced above and certifies to that effect, the distributor may expect that the determination of the final account balance will be handled expeditiously and in largely administrative manner." The Corporation received a Decision and Order for final disposition with the 2012 IRM Application for rates effective May 1, 2012. The Corporation's distribution revenue has been decreased by approximately $760,000 and net carrying charges have been reduced by approximately $196,000 as a result of the decision. The adjustments were mainly reversing previously "trued-up" items with respect to regulatory asset movements (given the closing of the account causing incomplete cycle of the movements) and inclusion of the OEB approved PILs proxies during the rate freeze period imposed by Bill 210 in 2002.

4. CORPORATE INCOME AND CAPITAL TAXES

The provision for payments in lieu of corporate income and capital taxes differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate.

The impact of differences between the Corporation's reported income tax expense on operating income and the expense that would otherwise result from the application of statutory rates is as follows:

	2011	2010
	$	$
Earnings before provision for taxes	**2,692,266**	735,032
Statutory Canadian federal and provincial income tax rate (%)	**28.25**	30.99
Expected provision	**760,565**	227,786
Apprenticeship tax credit	**(75,957)**	(70,825)
Ontario small business deduction	**(36,240)**	-
Amortization and capital cost allowance	**(65,287)**	(616,726)
Employee future benefits	**(16,831)**	(2,127)
Asset retirement obligation	**(2,322)**	87,032
Smart meter deferral	**87,930**	547,593
Permanent differences	**10,017**	80,767
Tax provision	**661,875**	253,500
Effective tax rate (%)	**25.62**	34.49

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

	2011 $	2010 $
Property, plant and equipment and intangible assets	**5,669,492**	5,849,343
Post-employment benefits liability	**698,040**	714,535
Asset retirement obligation	**22,790**	29,530
Regulatory accounts	**(1,781,822)**	(2,029,908)
	4,608,500	4,563,500

Presented on the balance sheet as follows:

	2011 $	2010 $
Future income tax assets, long-term	**6,397,615**	6,603,500
Future income tax liabilities, long-term	**1,789,115**	2,040,000

5. PROPERTY, PLANT AND EQUIPMENT

[a] Details of year-end property, plant and equipment balances are as follows:

	2011		2010	
	Cost	**Accumulated amortization**	Cost	Accumulated amortization
	$	$	$	$
Buildings	**3,935,354**	**1,790,868**	3,932,881	1,718,400
Distribution equipment	**139,088,445**	**70,956,890**	130,541,300	66,639,769
General office equipment	**4,225,180**	**3,800,710**	4,042,815	3,700,717
Land	**133,038**	**-**	133,038	-
Other equipment	**3,205,849**	**2,591,381**	3,143,135	2,504,603
Rolling stock	**6,536,995**	**4,531,615**	6,219,429	4,191,352
Transformation equipment	**8,639,193**	**6,051,061**	8,639,193	5,847,357
	165,764,054	**89,722,525**	156,651,791	84,602,198
Property, plant and equipment, net	**76,041,529**		72,049,593	

See note 12 for details of the amortization for the year.

[b] Details of year-end capital contributions balances are as follows:

	2011		2010	
	Capital contributions	**Accumulated amortization**	Capital contributions	Accumulated amortization
	$	$	$	$
Distribution equipment	**15,702,405**	**3,067,428**	12,744,352	2,439,332
Capital contributions, net	**12,634,977**		10,305,020	

See note 12 for details of the amortization for the year.

6. LONG-TERM DEBT

Long-term debt consists of the following:

	2011	2010
	$	$
Bank term loan payable in monthly instalments of $64,400 including interest at 5.27%, maturing July, 2024.	**7,100,320**	7,484,747
Less amounts included in current liabilities	**408,458**	387,529
Long-term portion	**6,691,862**	7,097,218

Principal repayments required over the next five years and thereafter are as follows:

	$
2012	408,458
2013	430,516
2014	453,766
2015	478,272
2016	504,101
Thereafter	4,825,207
	7,100,320

As collateral for the above loan, the Corporation has provided a general security agreement representing a first charge on all assets and undertaking, including without limitation, equipment specific to the Smart Meter Program.

7. BANK CREDITS

[a] The Corporation has an operating loan available in the amount of $6,395,495 [2010 - $6,395,495] by way of prime rate based loans or bankers' acceptances. At year-end, $nil [2010 - $nil] was utilized. The prime rate based loans bear interest at bank prime. Prime at December 31, 2011 was 3.0% [2010 - 3.0%]. The bankers' acceptances bear a stamping fee at 0.5% per annum.

The operating loan is secured by:

[i] Guarantee of Advance, unlimited, as executed by Thunder Bay Hydro Corporation; and
[ii] Subordination Agreement with respect to the $33,490,550 promissory note given to the City of Thunder Bay, with said Subordination Agreement providing for no acceleration rights, as approved by the Bank's legal department.

[b] The Corporation has a letter of credit or stand-by letters of guarantee available in the amount of $9,708,637 [2010 - $9,708,637] of which $9,708,637 [2010 - $9,708,637] was issued at December 31, 2011. This credit will be used by the Corporation to assist in meeting its prudential obligations to the Independent Electricity System Operator ("IESO"). The credit bears interest at bank prime. Prime at December 31, 2011 was 3.0% [2010 - 3.0%]. Amounts payable to the IESO are recorded in current liabilities on the balance sheet.

8. EMPLOYEE FUTURE BENEFITS

The Corporation has a number of unfunded benefit plans providing retirement and post-employment benefits (excluding pension) to most of its employees.

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

	2011 $	2010 $
Accrued benefit obligation at January 1	**2,849,661**	3,011,388
Actuarial (losses) gains	**118,894**	(199,983)
Current service costs	**121,735**	108,777
Interest cost	**131,868**	141,953
Benefits paid in the year or moved to current liability	**(390,446)**	(212,474)
Accrued benefit obligation, end of year	**2,831,712**	2,849,661
Projected accrued benefit obligation at December 31, using a 4.75% [2010 - 5.25%] discount rate	**2,831,712**	2,849,661
Unamortized actuarial gain (loss)	**(39,553)**	8,479
Accrued benefit liability	**2,792,159**	2,858,140

The main actuarial assumptions employed for the valuations are as follows:

[a] General inflation

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0%.

[b] Interest (discount) rate

The obligation as at December 31, 2011, of the present value of future liabilities and the expense for the year, were determined using an annual discount rate of 4.25%.

[c] Salary levels

Future general salary and wage levels were assumed to increase at 3.3% per annum.

[d] Medical costs

Medical costs were assumed to increase at a rate of 7.63% in 2011 graded-down by .37% per annum leveling off at 5% in 2018 and thereafter.

9. NOTE PAYABLE TO THE CORPORATION OF THE CITY OF THUNDER BAY

The note is a non-interest bearing note payable to The Corporation of the City of Thunder Bay (sole shareholder of Thunder Bay Hydro Corporation, the Corporation's parent company). Principal repayment in the next twelve months is expected to be $nil.

	2011 $	2010 $
Note payable to The Corporation of the City of Thunder Bay	**33,490,500**	33,490,500

10. ASSET RETIREMENT OBLIGATION

A reconciliation between the opening and closing ARO liability balances is as follows:

	2011 $	2010 $
Balance, beginning of year	**118,118**	525,119
Adjustment for change in estimates	**-**	(350,443)
ARO liabilities settled in the year	**(32,077)**	(47,495)
Accretion (recovery) expense	**5,119**	(9,063)
Balance, end of year	**91,160**	118,118

At December 31, 2011 the Corporation estimates the undiscounted amount of cash flows required over the nine years [2010 - ten years] to settle the ARO is $140,702 [2010 - $195,136]. A discount rate of 4.25% [2010 - 5.25%] was used to calculate the carrying value of the ARO liabilities. No assets have been restricted for settlement of the liability.

11. OTHER OPERATING REVENUE

	2011 $	2010 $
Pole line rentals	**464,701**	454,382
Competitive market revenues	**189,443**	200,237
Interest earned	**429,935**	101,164
Utility services	**359,563**	317,095
Reconnection and change in occupancy charges	**221,536**	269,676
Late payment charges	**297,478**	261,868
Sundry earnings	**397,243**	361,558
	2,359,899	1,965,980

12. AMORTIZATION

	2011 $	2010 $
Amortization of general plant	**5,198,537**	5,001,916
Amortization of capital contributions	**(628,096)**	(509,632)
Amortization of wholesale meters	**50,893**	35,240
Amortization of unallocated office and data processing equipment	**46,776**	54,813
	4,668,110	4,582,337
Amortization of other property, plant and equipment included in relevant expense categories in the Statement of Operations and Retained Earnings	**692,138**	639,369
	5,360,248	5,221,706
Amortization included in capitalized expenditures	**327,353**	258,662
Amortization of property, plant and equipment	**5,589,274**	5,407,115
Amortization of intangible assets	**71,717**	65,561
Amortization of capital contributions	**(628,096)**	(509,632)
	5,360,248	5,221,706

13. PENSION PLAN

The Corporation's current service pension costs for the year ended December 31, 2011 were $768,721 [2010 - $659,310].

14. STATEMENT OF CASH FLOWS

[a] The net change in non-cash working capital balances related to operations consists of the following:

	2011 $	2010 $
Decrease (increase) in current assets		
Accounts receivable	**(1,540,243)**	(430,677)
Unbilled revenue	**(1,927,499)**	757,267
Payments in lieu of corporate income taxes receivable	**1,542,753**	(183,221)
Due from related parties	**115,861**	613,828
Stores inventory	**(39,934)**	300,991
Prepaid expenses	**(85,902)**	(5,490)
	(1,934,964)	1,052,698
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	**387,016**	750,598
Debt retirement charges payable	**(29,391)**	(12,800)
Deferred revenue and contributions	**438,272**	(150,559)
Due to related party	**112,173**	-
Customer deposits	**(797,663)**	671,960
	110,407	1,259,199
	(1,824,557)	2,311,897

[b] During the year, property, plant and equipment were acquired at an aggregate cost of $11,155,051 [2010 - $9,689,992], of which $2,351,956 [2010 - $1,839,888] was funded by cash contributions, $606,097 [2010 - $659,761] was funded by contributions in-kind, $327,353 [2010 - $258,662] was funded by capitalized amortization, and $7,869,646 [2010 - $6,931,681] was funded by cash.

[c] During the year, assets acquired relating to the Smart Meter Initiative amounted to $170,744 [2010 - $422,663], of which $nil [2010 - $412,474] was funded by long-term debt, and $170,744 [2010 - $10,189] was funded by cash.

[d] Cash outflows (inflows) during the year for interest and income taxes were as follows:

	2011 $	2010 $
Interest paid (received)	**(329,210)**	816
Income taxes paid	**740,028**	916,644

15. RELATED PARTY TRANSACTIONS

The Corporation of the City of Thunder Bay

The Corporation provides certain services to The Corporation of the City of Thunder Bay (the Corporation's parent's shareholder) in the normal course of business at commercial rates.

For the year ended December 31, 2011, pole rental revenue from The Corporation of the City of Thunder Bay in the amount of $316,961 [2010 - $310,263] and other sundry revenues in the amount of $48,312 [2010 - $36,543] were recorded. The Corporation of the City of Thunder Bay also contributed towards capital construction during the year in the amount of $452,797 [2010 - $335,889]. Included in "Accounts receivable" is $213,659 [2010 - $10,625] receivable from The Corporation of the City of Thunder Bay related to these other activities.

For the year ended December 31, 2011, the Corporation billed electricity revenues in the amount of $8,060,667 [2010 - $9,191,485] to The Corporation of the City of Thunder Bay. At December 31, 2011, included in "Accounts receivable" is $614,298 [2010 - $299,644] receivable from The Corporation of the City of Thunder Bay, related to this electricity revenue.

The Corporation purchases certain services from The Corporation of the City of Thunder Bay in the normal course of business at commercial rates. For the year ended December 31, 2011, the Corporation was charged rent of $310,900 [2010 - $302,036], telecommunication capital and operating costs of $328,261 [2010 - $361,792], water billings of $7,612 [2010 - $8,133], and property taxes of $127,753 [2010 - $126,987].

Companies under Common Control

The Corporation provides services to Thunder Bay Hydro Utility Services Inc. ("TBHUSI") at cost plus the higher of bank prime and the Corporation's approved rate of return of 3.75%, effective May 1, 2009 [2.93% previously]. During 2011, the Corporation charged TBHUSI $273,837 [2010 - $231,877] for direct costs and administration fees.

The Corporation provides services to Thunder Bay Hydro Renewable Power Incorporated ("TBHRPI") for cost plus an annual administrative charge of $7,500 [2010 - $7,500]. During 2011, the Corporation charged TBHRPI $84,101 [2010 - $83,947] for direct costs and administration fees.

The Corporation also charged interest at bank prime on outstanding advances from TBHRPI. Interest charged during 2011 was $4,451 [2010 - $4,817].

The Corporation is reimbursed by Thunder Bay Hydro Corporation ("TBHC"), the parent company, for costs associated with the compensation for TBHC Board of Director fees at cost. During 2011, the Corporation charged TBHC $1,625 [2010 - $nil] for these direct costs.

Amounts owed:	**2011** $	2010 $
Owing (to) from TBHRPI	**(112,173)**	59,176
Owing from TBHUSI	**72,515**	125,446
Owing from TBHC	**1,455**	5,209
	(38,203)	189,831

The balance due to TBHRPI is unsecured and due on demand. Balances outstanding in excess of 30 days bear interest at prime.

16. FINANCIAL INSTRUMENTS

[a] Fair value

The Corporation's cash and cash equivalents, investments, accounts receivable, accounts payable and accrued liabilities, and customer deposits carrying values approximate fair value due to the short maturity of these balances.

The fair value of amounts due to/from related parties and the note payable can not be determined as there is no readily available comparative market.

The fair market value of the long-term debt approximates its carrying value.

[b] Risk factors

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

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

Credit risk

Financial instruments are exposed to credit risk as a result of the risk of the counter-party defaulting on its obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The Corporation provides reserves for credit risks based on the financial condition and short and long-term exposures to counter-parties.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from the Corporation's customers. The Corporation has approximately 49,800 customers, the majority of which are residential. The Corporation collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2011, the Corporation held security deposits in the amount of $1,568,154 [2010 - $1,862,140].

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 and Retained Earnings. Subsequent recoveries of receivables previously provisioned are credited to the Statement of Operations and Retained Earnings.

Credit risk associated with accounts receivable is as follows:

	2011 $	2010 $
Total accounts receivable	**9,637,227**	8,118,278
Less: Allowance for doubtful accounts	**(365,729)**	(387,023)
Total accounts receivable, net	**9,271,498**	7,731,255
Of which		
Outstanding for less than 30 days	**7,936,715**	6,530,369
Outstanding for more than 31 days but not more than 180 days	**1,175,300**	1,199,581
Outstanding for more than 181 days	**396,677**	333,957
Amounts unbilled	**128,535**	54,371
Less: Allowance for doubtful accounts	**(365,729)**	(387,023)
Total accounts receivable, net	**9,271,498**	7,731,255

Unbilled revenue represents amounts to which the Corporation has a contractual right to receive cash through future billings but are unbilled at year-end. As at December 31, 2011, total unbilled revenue is $13,517,342 [2010 - $11,589,843]. Unbilled revenue outstanding is considered current.

At December 31, 2011, there were no significant concentrations of credit risk with respect to any class of financial assets or counterparties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk

The Corporation is exposed to interest rate risk in holding certain financial instruments. The Corporation's objective is to minimize net interest expense. Under the Corporation's Revolving Credit Facility, the Corporation may obtain short-term borrowings for working capital purposes. These borrowings expose the Corporation to fluctuations in short-term interest rate [borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit]. The fee payable for bankers' acceptances and letters of credit is based on 0.5% fee per annum plus stamping fee when applicable.

Cash balances that are not required to meet day-to-day obligations of the Corporation are periodically invested in short-term Canadian money market instruments, exposing the Corporation to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by the Corporation.

Liquidity risk

The Corporation monitors and manages 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 is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to credit facilities and

monitors cash balances regularly to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risks associated with financial commitments are as follows:

	December 31, 2011		
	Due within 1 year $	Due between 1 year and 5 years $	Due after 5 years $
Financial liabilities			
Accounts payable and accrued liabilities	13,105,494	-	-
Note payable to The Corporation of the City of Thunder Bay	-	-	33,490,500
Long-term debt	408,458	1,866,656	4,825,206

Foreign exchange risk

As at December 31, 2011, the Corporation has limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in U.S. dollars, and purchases U.S. currency to meet the related payables commitments when required, the impact of these transactions is not material to the financial statements.

17. LIABILITY INSURANCE

The Corporation belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2011, the Corporation has not been made aware of any assessments for losses.

18. CAPITAL DISCLOSURES

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

- ensure ongoing access to funding in order to maintain and improve the electricity distribution system of the Corporation;
- ensure compliance with covenants related to its credit facilities and the note payable to The Corporation of the City of Thunder Bay ("City Note");
- begin to align its capital structure for regulated activities of the Corporation with the debt to equity structure recommended by the OEB.

As of December 31, 2011, the Corporation's definition of capital includes shareholder's equity and long-term debt and has remained unchanged from December 31, 2010. As of December 31, 2011, shareholder's equity amounts to $47,379,920 [2010 - $45,349,529]

and long-term debt amounts to $40,590,820 [2010 - $40,975,247]. The Corporation's long-term capital structure at December 31, 2011 is 46% debt and 54% equity [2010 - 47% debt and 53% equity]. There have been no changes in the Corporation's approach to capital management during the year.

As at December 31, 2011, the Corporation is subject to debt agreements that contain various covenants. The Corporation is governed by the Shareholder Declaration which limits future borrowings, liens, and provisions of security without prior written consent. The Corporation is also subject to a Subordination Agreement with respect to the $33,490,550 promissory note given to The Corporation of the City of Thunder Bay, with said Subordination Agreement providing for no acceleration rights, as approved by the Bank's legal department.

The Corporation's revolving credit facility limits the debt to capitalization ratio to a maximum of 60% [2010 - 60%] and a debt service coverage ratio of not less than 1.20:1 [2010 - 1.20:1]. As at December 31, 2011, the debt to capitalization ratio was 18% [2010 - 17%] and debt service coverage was 8.1:1 [2010 - 5.3:1]. The Corporation's long-term debt agreements also include positive and negative covenants such as limitations on funded indebtedness, capital expenditures restrictions on mergers, amalgamations or consolidations, and limitations on providing security or guarantees to any third party. As at December 31, 2011, the Corporation was in compliance with the financial covenants included in its long-term debt agreements, City Note and short-term revolving credit facility.

19. COMPARATIVE AMOUNTS

Certain comparative amounts presented in the financial statements have been reclassified to conform to current year's presentation.

Thunder Bay Hydro Electricity Distribution Inc.
Schedule - Expenses

Year ended December 31	2011	2010
	$	$
OPERATIONS AND MAINTENANCE		
Customer premises/meters and devices	**327,723**	312,909
Distribution	**3,634,110**	4,053,585
Safety and training	**436,851**	434,553
System control/station maintenance	**1,652,587**	1,567,393
Transformer	**711,034**	628,191
Total operations and maintenance expenses	**6,762,305**	6,996,631
ADMINISTRATION		
Bad debts	**84,356**	31,790
Billing and collecting	**959,401**	1,112,638
Customer information service	**1,001,680**	1,078,791
Information services	**766,861**	790,542
Meter reading	**99,386**	164,601
Total customer - related administration expenses	**2,911,684**	3,178,362
General		
Corporate	**587,448**	498,974
Directors' expenses	**93,706**	62,398
Finance	**870,153**	784,247
Human resources	**346,891**	345,472
President's office	**364,359**	349,069
Power systems administration	**260,734**	297,617
Renewable generation activities	**175,638**	214,682
Total general administration expenses	**2,698,929**	2,552,459
Total administration expenses	**5,610,613**	5,730,821

APPENDIX 1-C

Thunder Bay Hydro
2012 Pro Forma Financial Statements
CGAA

Thunder Bay Hydro Electricity Distribution Inc.
, License Number ED-2002-0529, File Number EB-2012-0167

Thunder Bay Hydro Electricity Distribution Inc.
2012 BALANCE SHEET

Account Description	Total	Total	Total
1050-Current Assets		**Non Wires**	**Consolidated**
1005-Cash	10,309,533	(208,647)	10,100,886
1010-Cash Advances and Working Funds	600	0	600
1020-Interest Special Deposits	0	0	0
1030-Dividend Special Deposits	0	0	0
1040-Other Special Deposits	814	0	814
1060-Term Deposits	0	0	0
1070-Current Investments	32,025	0	32,025
1100-Customer Accounts Receivable	7,699,402	0	7,699,402
1102-Accounts Receivable - Services	0	0	0
1104-Accounts Receivable - Recoverable Work	189,181	0	189,181
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0	0	0
1110-Other Accounts Receivable	407,911	0	407,911
1120-Accrued Utility Revenues	13,517,342	0	13,517,342
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(365,729)	0	(365,729)
1140-Interest and Dividends Receivable	9,319	0	9,319
1150-Rents Receivable	0	0	0
1170-Notes Receivable	0	0	0
1180-Prepayments	290,987	0	290,987
1190-Miscellaneous Current and Accrued Assets	0	0	0
1200-Accounts Receivable from Associated Companies	717,073	0	717,073
1210-Notes Receivable from Associated Companies	0	0	0
1050-Current Assets Total	**32,808,457**	**(208,647)**	**32,599,810**

1100-Inventory			
1305-Fuel Stock	0	0	0
1330-Plant Materials and Operating Supplies	1,310,812	0	1,310,812
1340-Merchandise	0	0	0
1350-Other Material and Supplies	0	0	0
1100-Inventory Total	**1,310,812**	**0**	**1,310,812**

1150-Non-Current Assets			
1405-Long Term Investments in Non-Associated Companies	0	0	0
1408-Long Term Receivable - Street Lighting Transfer	0	0	0
1410-Other Special or Collateral Funds	0	0	0

1415-Sinking Funds	0	0	0
1425-Unamortized Debt Expense	0	0	0
1445-Unamortized Discount on Long-Term Debt--Debit	0	0	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0	0	0
1460-Other Non-Current Assets (Hydro One Gate Stations)	1,135,295	0	1,135,295
1465-O.M.E.R.S. Past Service Costs	0	0	0
1470-Past Service Costs - Employee Future Benefits	0	0	0
1475-Past Service Costs -Other Pension Plans	0	0	0
1480-Portfolio Investments - Associated Companies	0	0	0
1485-Investment In Subsidiary Companies - Significant Influence	0	0	0
1490-Investment in Subsidiary Companies	0	0	0
1150-Non-Current Assets Total	**1,135,295**	**0**	**1,135,295**

1200-Other Assets and Deferred Charges			
1505-Unrecovered Plant and Regulatory Study Costs	0	0	0
1508-Other Regulatory Assets	102,976	0	102,976
1510-Preliminary Survey and Investigation Charges	0	0	0
1515-Emission Allowance Inventory	0	0	0
1516-Emission Allowance Withheld	0	0	0
1518-RCVA Retail	176,487	0	176,487
1521-SPC Assessment variance Account	0	0	0
1525-Miscellaneous Deferred Debits	0	0	0
1530-Deferred Losses from Disposition of Utility Plant	0	0	0
1540-Deferred Losses from Disposition of Utility Plant	0	0	0
1545-Development Charge Deposits/ Receivables	0	0	0
1548-RCVA - Service Transaction Request (STR)	165,693	0	165,693
1550-LV Charges - Variance	0	0	0
1555-Smart Meters Recovery	1,567,432	0	1,567,432
1556-Smart Meters OM & A	1	0	1
1562-Deferred PILs	1	0	1
1563-Deferred PILs - Contra	0	0	0
1565-C & DM Costs	0	0	0
1566-C & DM Costs Contra	0	0	0
1570-Qualifying Transition Costs	0	0	0
1572-Extraordinary Event Losses	0	0	0
1574-Deferred Rate Impact Amounts	0	0	0
1575-IFRS-CGAAP Transition PP&E	0	0	0
1580-RSVA - Wholesale Market Services	(2,911,849)	0	(2,911,849)
1582-RSVA - One-Time	0	0	0
1584-RSVA - Network Charges	(485,261)	0	(485,261)
1586-RSVA - Connection Charges	(865,843)	0	(865,843)
1588-RSVA - Commodity (Power)	(372,723)	0	(372,723)

1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0	0	0
1595-Disposition and Recovery of Regulatory Balances	(451,992)	0	(451,992)
1609-Intangible Assets - Capital Contribution	0	0	0
1200-Other Assets and Deferred Charges Total	**(3,075,078)**	**0**	**(3,075,078)**

1450-Distribution Plant		**Non Wires**	**Consolidated**
1805-Land	133,038	0	133,038
1806-Land Rights	0	0	0
1808-Buildings and Fixtures	3,932,848	0	3,932,848
1810-Leasehold Improvements	75,507	0	75,507
1820-Distribution Station Equipment - ARO	0	0	0
1820-Distribution Station Equipment - Normally Primary below 50 kV	8,124,042	0	8,124,042
1825-Storage Battery Equipment	0	0	0
1830-Poles, Towers and Fixtures	33,222,322	0	33,222,322
1835-Overhead Conductors and Devices	33,417,559	0	33,417,559
1840-Underground Conduit	13,902,980	0	13,902,980
1845-Underground Conductors and Devices	19,183,316	0	19,183,316
1850-Line Transformers	28,501,475	0	28,501,475
1855-Services	20,869,912	0	20,869,912
1860-Meters	9,212,343	0	9,212,343
1865-Other Installations on Customer's Premises	0	0	0
1450-Distribution Plant Total	**170,575,340**	**0**	**170,575,340**

1500-General Plant		**Non Wires**	**Consolidated**
1905-Land	0	0	0
1906-Land Rights	0	0	0
1908-Buildings and Fixtures	0	0	0
1910-Leasehold Improvements	0	0	0
1915-Office Furniture and Equipment	1,420,039	0	1,420,039
1920-Computer Equipment - Hardware	2,955,562	0	2,955,562
1925-Computer Software	1,179,533	0	1,179,533
1930-Transportation Equipment	6,543,849	0	6,543,849
1935-Stores Equipment	63,417	0	63,417
1940-Tools, Shop and Garage Equipment	2,516,457	0	2,516,457
1945-Measurement and Testing Equipment	294,334	0	294,334
1950-Power Operated Equipment	194,622	0	194,622
1955-Communication Equipment	240,489	0	240,489
1960-Miscellaneous Equipment	0	0	0
1970-Load Management Controls - Customer Premises	0	0	0
1975-Load Management Controls - Utility Premises	0	0	0
1980-System Supervisory Equipment	566,626	0	566,626
1985-Sentinel Lighting Rentals	(0)	82,215	82,215

1990-Other Tangible Property	0	0	0
1995-Contributions and Grants	(17,725,330)	0	(17,725,330)
1500-General Plant Total	**(1,750,403)**	**82,215**	**(1,668,188)**

1550-Other Capital Assets		**Non Wires**	**Consolidated**
2005-Property Under Capital Leases	0	0	0
2010-Electric Plant Purchased or Sold	0	0	0
2020-Experimental Electric Plant Unclassified	0	0	0
2030-Electric Plant and Equipment Leased to Others	0	0	0
2040-Electric Plant Held for Future Use	0	0	0
2050-Completed Construction Not Classified--Electric	0	0	0
2055-Construction Work in Progress--Electric	1,268,794	0	1,268,794
2060-Electric Plant Acquisition Adjustment	0	0	0
2065-Other Electric Plant Adjustment	0	0	0
2070-Other Utility Plant	0	0	0
2075-Non-Utility Property Owned or Under Capital Lease	0	52,664	52,664
1550-Other Capital Assets Total	**1,268,794**	**52,664**	**1,321,458**

1600-Accumulated Amortization		**Non Wires**	**Consolidated**
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(94,226,592)	(25,274)	(94,251,866)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	0	0	0
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0	0	0
2160-Accumulated Amortization of Other Utility Plant	0	0	0
2180-Accumulated Amortization of Non-Utility Property	0	0	0
1600-Accumulated Amortization Total	**(94,226,592)**	**(25,274)**	(94,251,866)

Total Assets	**108,046,626**	**(99,042)**	**107,947,584**

1650-Current Liabilities		**Non Wires**	**Consolidated**
2205-Accounts Payable	10,331,443	0	10,331,443
2208-Customer Credit Balances	769,752	0	769,752
2210-Current Portion of Customer Deposits	1,715,566	0	1,715,566
2215-Dividends Declared	0	0	0
2220-Miscellaneous Current and Accrued Liabilities	1,604,862	0	1,604,862
2225-Notes and Loans Payable	0	0	0
2240-Accounts Payable to Associated Companies	37,524	0	37,524
2242-Notes Payable to Associated Companies	0	0	0
2250-Debt Retirement Charges (DRC) Payable	504,235	0	504,235
2252-Transmission Charges Payable	0	0	0
2254-Electric Safety Authority Fees Payable	0	0	0
2256-Independent Market Operator Fees and Penalties Payable	0	0	0

2260-Current Portion of Long Term Debt	603,513	0	603,513
2262-Ontario Hydro Debt - Current Portion	0	0	0
2264-Pensions and Employee Benefits - Current Portion	0	0	0
2268-Accrued Interest on Long Term Debt	0	0	0
2270-Matured Long Term Debt	0	0	0
2272-Matured Interest on Long Term Debt	0	0	0
2285-Obligations Under Capital Leases--Current	0	0	0
2290-Commodity Taxes	(919,542)	0	(919,542)
2292-Payroll Deductions / Expenses Payable	236,548	0	236,548
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	14,835	0	14,835
2296-Future Income Taxes - Current	0	0	0
1650-Current Liabilities Total	**14,898,735**	**0**	**14,898,735**

1700-Non-Current Liabilities		**Non Wires**	**Consolidated**
2305-Accumulated Provision for Injuries and Damages	0	0	0
2306-Employee Future Benefits	2,165,961	0	2,165,961
2308-Other Pensions - Past Service Liability	0	0	0
2310-Vested Sick Leave Liability	626,198	0	626,198
2315-Accumulated Provision for Rate Refunds	0	0	0
2320-Other Miscellaneous Non-Current Liabilities (includes ARO)	650,512	0	650,512
2325-Obligations Under Capital Lease--Non-Current	0	0	0
2330-Devolpment Charge Fund	0	0	0
2335-Long Term Customer Deposits	0	0	0
2340-Collateral Funds Liability	0	0	0
2345-Unamortized Premium on Long Term Debt	0	0	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0	0	0
2350-Future Income Tax - Non-Current	(4,532,500)	0	(4,532,500)
2405-Other Regulatory Liabilities	0	0	0
2410-Deferred Gains From Disposition of Utility Plant	0	0	0
2415-Unamortized Gain on Reacquired Debt	0	0	0
2425-Other Deferred Credits	0	0	0
2440-Deferred Revenue	0	0	0
1700-Non-Current Liabilities Total	**(1,089,830)**	**0**	**(1,089,830)**

1800-Long-Term Debt		**Non Wires**	**Consolidated**
2505-Debentures Outstanding - Long Term Portion	0	0	0
2510-Debenture Advances	0	0	0
2515-Required Bonds	0	0	0
2520-Other Long Term Debt	0	0	0
2525-Term Bank Loans - Long Term Portion	12,278,832	0	12,278,832
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0	0	0
2550-Advances from Associated Companies	33,490,500	0	33,490,500
1800-Long-Term Debt Total	**45,769,332**	**0**	**45,769,332**

1850-Shareholders' Equity		Non Wires	Consolidated
3005-Common Shares Issued	21,899,072	0	21,899,072
3008-Preference Shares Issued	0	0	0
3010-Contributed Surplus	0	0	0
3020-Donations Received	0	0	0
3022-Devolpment Charges Transferred to Equity	0	0	0
3026-Capital Stock Held in Treasury	0	0	0
3030-Miscellaneous Paid-In Capital	13,032,554	0	13,032,554
3035-Installments Received on Capital Stock	0	0	0
3040-Appropriated Retained Earnings	0	0	0
3045-Unappropriated Retained Earnings	12,448,295		12,448,295
3046-Balance Transferred From Income	1,088,466	(99,042)	989,424
3047-Appropriations of Retained Earnings - Current Period	0	0	0
3048-Dividends Payable-Preference Shares	0	0	0
3049-Dividends Payable-Common Shares	0	0	0
3055-Adjustment to Retained Earnings	0	0	0
3065-Unappropriated Undistributed Subsidiary Earnings	0	0	0
1850-Shareholders' Equity Total	**48,468,388**	**(99,042)**	**48,369,346**

Total Liabilities & Shareholder's Equity	**108,046,626**	**(99,042)**	**107,947,584**

Balance Sheet Total	(0)	0	(0)

Thunder Bay Hydro Electricity Distribution Inc.
, License Number ED-2002-0529, File Number EB-2012-0167

Thunder Bay Hydro Electricity Distribution Inc.
2012 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total	Total	Total
3000-Sales of Electricity		**Non Wires**	**Consolidated**
4006-Residential Energy Sales	(26,226,075)	0	(26,226,075)
4010-Commercial Energy Sales	0	0	0
4015-Industrial Energy Sales	0	0	0
4020-Energy Sales to Large Users	0	0	0
4025-Energy Sales to Street Lights	0	0	0
4030-Energy Sales to Sentinel Lighting	(10,153)	(6,000)	(16,153)
4035-General Energy Sales	(44,678,197)	0	(44,678,197)
4040-Other Energy Sales to Public Authorities	0	0	0
4045-Energy Sales to Railroads and Railways	0	0	0
4050-Revenue Adjustment	(1,372,557)	0	(1,372,557)
4055-Energy Sales for Resale	(6,842,064)	0	(6,842,064)
4060-Interdepartmental Energy Sales	(199,000)	0	(199,000)
4062-WMS	(6,229,189)	0	(6,229,189)
4064-Billed WMS-One Time	0	0	0
4066-NS	(6,467,045)	0	(6,467,045)
4068-CS	(4,782,316)	0	(4,782,316)
4075-LV Charges	0	0	0
3000-Sales of Electricity Total	**(96,806,595)**	**(6,000)**	**(96,812,595)**
3050-Revenues From Services - Distribution		**Non Wires**	**Consolidated**
4080-Distribution Services Revenue	(21,515,254)	0	(21,515,254)
4080-2-SSS Revenue	(131,340)	0	(131,340)
4082-RS Rev	(59,150)	0	(59,150)
4084-Serv Tx Requests	(1,900)	0	(1,900)
4080-3-One Time Distribution Revenues	489,775	0	489,775
3050-Revenues From Services - Distribution Total	**(21,217,869)**	**0**	**(21,217,869)**
3100-Other Operating Revenues		**Non Wires**	**Consolidated**
4205-Interdepartmental Rents	0	0	0
4210-Rent from Electric Property	(471,000)	0	(471,000)
4215-Other Utility Operating Income	0	0	0
4220-Other Electric Revenues	(168,726)	0	(168,726)
4225-Late Payment Charges	(297,000)	0	(297,000)
4230-Sales of Water and Water Power	0	0	0
4235-Miscellaneous Service Revenues	(274,216)	0	(274,216)

4240-Provision for Rate Refunds	0	0	0
4245-Government Assistance Directly Credited to Income	0	0	0
3100-Other Operating Revenues Total	**(1,210,942)**	**0**	**(1,210,942)**

3150-Other Income & Deductions		**Non Wires**	**Consolidated**
4305-Regulatory Debits	0	0	0
4310-Regulatory Credits	0	0	0
4315-Revenues from Electric Plant Leased to Others	0	0	0
4320-Expenses of Electric Plant Leased to Others	0	0	0
4324-SPC Recovery	0	0	0
4325-Revenues from Merchandise, Jobbing, Etc.	0	0	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0	0	0
4335-Profits and Losses from Financial Instrument Hedges	0	0	0
4340-Profits and Losses from Financial Instrument Investments	0	0	0
4345-Gains from Disposition of Future Use Utility Plant	0	0	0
4350-Losses from Disposition of Future Use Utility Plant	0	0	0
4355-Gain on Disposition of Utility and Other Property	12,200	0	12,200
4362-Loss from Retirement of Utility and Other Property	0	0	0
4365-Gains from Disposition of Allowances for Emission	0	0	0
4370-Losses from Disposition of Allowances for Emission	0	0	0
4375-Revenues from Non-Utility Operations	(879,343)	0	(879,343)
4380-Expenses of Non-Utility Operations	890,954	93,842	984,796
4385-Expenses of Non-Utility Operations	0	0	0
4390-Miscellaneous Non-Operating Income	(278,000)	0	(278,000)
4395-Rate-Payer Benefit Including Interest	0	0	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0	0	0
3150-Other Income & Deductions Total	**(254,189)**	**93,842**	**(160,347)**

3200-Investment Income		**Non Wires**	**Consolidated**
4405-Interest and Dividend Income	99,807	0	99,807
4415-Equity in Earnings of Subsidiary Companies	0	0	0
3200-Investment Income Total	**99,807**	**0**	**99,807**

3350-Power Supply Expenses		**Non Wires**	**Consolidated**
4705-Power Purchased	79,126,826	0	79,126,826
4708-WMS	6,253,534	0	6,253,534
4710-Cost of Power Adjustments	0	0	0
4712-0	0	0	0
4714-NW	6,539,239	0	6,539,239
4715-System Control and Load Dispatching	0	0	0
4716-NCN	4,886,996	0	4,886,996
4720-Other Expenses	0	0	0

4725-Competition Transition Expense	0	0	0
4730-Rural Rate Assistance Expense	0	0	0
4750-LV Charges	0	0	0
3350-Power Supply Expenses Total	**96,806,595**	**0**	**96,806,595**

3500-Distribution Expenses - Operation		**Non Wires**	**Consolidated**
5005-Operation Supervision and Engineering	319,363	0	319,363
5010-Load Dispatching	770,384	0	770,384
5012-Station Buildings and Fixtures Expense	337,791	0	337,791
5014-Transformer Station Equipment - Operation Labour	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0
5016-Distribution Station Equipment - Operation Labour	0	0	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	191,755	0	191,755
5020-Overhead Distribution Lines and Feeders - Operation Labour	122,232	0	122,232
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	643,937	0	643,937
5030-Overhead Subtransmission Feeders - Operation	0	0	0
5035-Overhead Distribution Transformers - Operation	151,597	0	151,597
5040-Underground Distribution Lines and Feeders - Operation Labour	24,260	0	24,260
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	10,377	0	10,377
5050-Underground Subtransmission Feeders - Operation	0	0	0
5055-Underground Distribution Transformers - Operation	190,708	0	190,708
5060-Street Lighting and Signal System Expense	0	0	0
5065-Meter Expense	270,936	0	270,936
5070-Customer Premises - Operation Labour	(921)	0	(921)
5075-Customer Premises - Materials and Expenses	13,687	0	13,687
5085-Miscellaneous Distribution Expense	11,452	0	11,452
5090-Underground Distribution Lines and Feeders - Rental Paid	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0
5096-Other Rent	0	0	0
3500-Distribution Expenses - Operation Total	**3,057,560**	**0**	**3,057,560**

3550-Distribution Expenses - Maintenance		**Non Wires**	**Consolidated**
5105-Maintenance Supervision and Engineering	679,578	0	679,578
5110-Maintenance of Structures	16,809	0	16,809
5112-Maintenance of Transformer Station Equipment	0	0	0
5114-Mtaint Dist Stn Equip	147,168	0	147,168
5120-Maintenance of Poles, Towers and Fixtures	231,209	0	231,209
5125-Maintenance of Overhead Conductors and Devices	687,512	0	687,512
5130-Maintenance of Overhead Services	375,517	0	375,517

5135-Overhead Distribution Lines and Feeders - Right of Way	700,172	0	700,172
5145-Maintenance of Underground Conduit	37,576	0	37,576
5150-Maintenance of Underground Conductors and Devices	153,642	0	153,642
5155-Maintenance of Underground Services	100,218	0	100,218
5160-Maintenance of Line Transformers	147,481	0	147,481
5165-Maintenance of Street Lighting and Signal Systems	0	0	0
5170-Sentinel Lights - Labour	0	7,752	7,752
5172-Sentinel Lights - Materials and Expenses	0	0	0
5175-Maintenance of Meters-Smart Meter LTD 2009-2011 Costs here	608,695	0	608,695
5178-Customer Installations Expenses - Leased Property	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0
3550-Distribution Expenses - Maintenance Total	**3,885,577**	**7,752**	**3,893,329**

3650-Billing and Collecting		**Non Wires**	**Consolidated**
5305-Supervision	0	0	0
5310-Meter Reading Expense	352,233	0	352,233
5315-Customer Billing	1,178,041	0	1,178,041
5320-Collecting	536,861	0	536,861
5325-Collecting - Cash Over and Short	0	0	0
5330-Collection Charges	0	0	0
5335-Bad Debt Expense	130,000	0	130,000
5340-Miscellaneous Customer Accounts Expenses	0	0	0
3650-Billing and Collecting Total	**2,197,135**	**0**	**2,197,135**

3700-Community Relations		**Non Wires**	**Consolidated**
5405-Supervision	0	0	0
5410-Community Relations - Sundry	0	0	0
5415-Energy Conservation	112,519	0	112,519
5420-Community Safety Program	16,800	0	16,800
5425-Miscellaneous Customer Service and Informational Expenses	0	0	0
3700-Community Relations Total	**129,319**	**0**	**129,319**

Sales Expense		**Non Wires**	**Consolidated**
5505-Supervision	0	0	0
5510-Demonstrating and Selling Expense	0	0	0
5515-Advertising Expense	99,955	0	99,955
5520-Miscellaneous Sales Expense	0	0	0
Sales Expense Total	**99,955**	**0**	**99,955**

3800-Administrative and General Expenses		**Non Wires**	**Consolidated**
5605-Executive Salaries and Expenses	879,590	0	879,590

5610-Management Salaries and Expenses	0	0	0
5615-General Administrative Salaries and Expenses	1,238,491	0	1,238,491
5620-Office Supplies and Expenses	281,790	0	281,790
5625-Administrative Expense Transferred-Credit	0	0	0
5630-Outside Services Employed	299,305	0	299,305
5635-Property Insurance	31,291	0	31,291
5640-Injuries and Damages	239,492	0	239,492
5645-Employee Pensions and Benefits	728,593	0	728,593
5650-Franchise Requirements	0	0	0
5655-Regulatory Expenses	202,340	0	202,340
5660-General Advertising Expenses	0	0	0
5665-Miscellaneous Expenses	111,167	0	111,167
5670-Rent	281,678	0	281,678
5675-Maintenance of General Plant	105,680	0	105,680
5680-Electrical Safety Authority Fees	0	0	0
5681-SPC Expense	0	0	0
5685-Independent Market Operator Fees and Penalties	0	0	0
5695-OM&A Contra Account	0	0	0
3800-Administrative and General Expenses Total	**4,399,417**	**0**	**4,399,417**

3850-Amortization Expense		**Non Wires**	**Consolidated**
5705-Amortization Expense - Property, Plant and Equipment	6,809,646	3,448	6,813,094
5710-Amortization of Limited Term Electric Plant	0	0	0
5715-Amortization of Intangibles and Other Electric Plant	0	0	0
5720-Amortization of Electric Plant Acquisition Adjustments	0	0	0
5725-Miscellaneous Amortization	50,893	0	50,893
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0	0	0
5735-Amortization of Deferred Development Costs	0	0	0
5740-Amortization of Deferred Charges	0	0	0
3850-Amortization Expense Total	**6,860,539**	**3,448**	**6,863,987**

3900-Interest Expense		**Non Wires**	**Consolidated**
6005-Interest on Long Term Debt	382,893	0	382,893
6010-Amortization of Debt Discount and Expense	0	0	0
6015-Amortization of Premium on Debt-Credit	0	0	0
6020-Amortization of Loss on Reacquired Debt	0	0	0
6025-Amortization of Gain on Reacquired Debt-Credit	0	0	0
6030-Interest on Debt to Associated Companies	0	0	0
6035-Other Interest Expense	122,331	0	122,331
6040-Allowance for Borrowed Funds Used During Construction-Credit	0	0	0
6042-Allowance for Other Funds Used During Construction	0	0	0

6045-Interest Expense on Capital Lease Obligations	0	0	0
3900-Interest Expense Total	**505,224**	**0**	**505,224**
3950-Taxes Other Than Income Taxes		**Non Wires**	**Consolidated**
6105-Taxes Other Than Income Taxes	0	0	0
3950-Taxes Other Than Income Taxes Total	**0**	**0**	**0**
4000-Income Taxes		**Non Wires**	**Consolidated**
6110-Income Taxes	267,500	0	267,500
6115-Provision for Future Income Taxes	76,000	0	76,000
4000-Income Taxes Total	**343,500**	**0**	**343,500**
4100-Extraordinary & Other Items		**Non Wires**	**Consolidated**
6205-Donations	16,500	0	16,500
6210-Life Insurance	0	0	0
6215-Penalties	0	0	0
6225-Other Deductions	0	0	0
4100-Extraordinary & Other Items Total	**16,500**	**0**	**16,500**
Net Income - (Gain)/Loss	**(1,088,466)**	**99,042**	**(989,424)**

APPENDIX 1-D

Thunder Bay Hydro
2013 Pro Forma Financial Statements
CGAAP

1

Thunder Bay Hydro Electricity Distribution Inc.
, License Number ED-2002-0529, File Number EB-2012-0167

Thunder Bay Hydro Electricity Distribution Inc.
2013 BALANCE SHEET

Account Description	Total	Total	Total
1050-Current Assets		**Non Wires**	**Consolidated**
1005-Cash	10,469,041	(210,472)	10,258,569
1010-Cash Advances and Working Funds	600	0	600
1020-Interest Special Deposits	0	0	0
1030-Dividend Special Deposits	0	0	0
1040-Other Special Deposits	814	0	814
1060-Term Deposits	0	0	0
1070-Current Investments	32,025	0	32,025
1100-Customer Accounts Receivable	7,699,402	0	7,699,402
1102-Accounts Receivable - Services	0	0	0
1104-Accounts Receivable - Recoverable Work	112,286	0	112,286
1105-Accounts Receivable - Merchandise, Jobbing, etc.	0	0	0
1110-Other Accounts Receivable	507,856	0	507,856
1120-Accrued Utility Revenues	13,517,342	0	13,517,342
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(365,729)	0	(365,729)
1140-Interest and Dividends Receivable	9,319	0	9,319
1150-Rents Receivable	0	0	0
1170-Notes Receivable	0	0	0
1180-Prepayments	290,987	0	290,987
1190-Miscellaneous Current and Accrued Assets	0	0	0
1200-Accounts Receivable from Associated Companies	717,073	0	717,073
1210-Notes Receivable from Associated Companies	0	0	0
1050-Current Assets Total	**32,991,015**	**(210,472)**	**32,780,543**

1100-Inventory		**Non Wires**	**Consolidated**
1305-Fuel Stock	0	0	0
1330-Plant Materials and Operating Supplies	1,389,059	0	1,389,059
1340-Merchandise	0	0	0
1350-Other Material and Supplies	0	0	0
1100-Inventory Total	**1,389,059**	**0**	**1,389,059**

1150-Non-Current Assets		**Non Wires**	**Consolidated**
1405-Long Term Investments in Non-Associated Companies	0	0	0
1408-Long Term Receivable - Street Lighting Transfer	0	0	0
1410-Other Special or Collateral Funds	0	0	0
1415-Sinking Funds	0	0	0

1425-Unamortized Debt Expense	0	0	0
1445-Unamortized Discount on Long-Term Debt--Debit	0	0	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0	0	0
1460-Other Non-Current Assets (Hydro One Gate Stations)	0	0	0
1465-O.M.E.R.S. Past Service Costs	0	0	0
1470-Past Service Costs - Employee Future Benefits	0	0	0
1475-Past Service Costs -Other Pension Plans	0	0	0
1480-Portfolio Investments - Associated Companies	0	0	0
1485-Investment In Subsidiary Companies - Significant Influence	0	0	0
1490-Investment in Subsidiary Companies	0	0	0
1150-Non-Current Assets Total	**0**	**0**	**0**

1200-Other Assets and Deferred Charges		**Non Wires**	**Consolidated**
1505-Unrecovered Plant and Regulatory Study Costs	0	0	0
1508-Other Regulatory Assets	72,491	0	72,491
1510-Preliminary Survey and Investigation Charges	0	0	0
1515-Emission Allowance Inventory	0	0	0
1516-Emission Allowance Withheld	0	0	0
1518-RCVA Retail	62,163	0	62,163
1521-SPC Assessment variance Account	0	0	0
1531-Renewable Enabling Improvements Deferral Account	375,786	0	375,786
1532-Renewable Enabling Improvements Deferral Account	(8,303)	0	(8,303)
1533-Renewable Enabling Improvements Deferral Account	(344,936)	0	(344,936)
1545-Development Charge Deposits/ Receivables	0	0	0
1548-RCVA - Service Transaction Request (STR)	62,164	0	62,164
1550-LV Charges - Variance	0	0	0
1555-Smart Meters Recovery	522,471	0	522,471
1556-Smart Meters OM & A	1	0	1
1562-Deferred PILs	1	0	1
1563-Deferred PILs - Contra	0	0	0
1565-C & DM Costs	0	0	0
1566-C & DM Costs Contra	0	0	0
1570-Qualifying Transition Costs	0	0	0
1572-Extraordinary Event Losses	0	0	0
1574-Deferred Rate Impact Amounts	0	0	0
1575-IFRS-CGAAP Transition PP&E	0	0	0
1580-RSVA - Wholesale Market Services	(2,891,582)	0	(2,891,582)
1582-RSVA - One-Time	0	0	0
1584-RSVA - Network Charges	(489,998)	0	(489,998)
1586-RSVA - Connection Charges	(869,261)	0	(869,261)
1588-RSVA - Commodity (Power)	(360,582)	0	(360,582)

1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0	0	0
1595-Disposition and Recovery of Regulatory Balances	125,365	0	125,365
1609-Intangible Assets - Capital Contribution	1,272,321	0	1,272,321
1200-Other Assets and Deferred Charges Total	**(2,471,899)**	**0**	**(2,471,899)**

1450-Distribution Plant		**Non Wires**	**Consolidated**
1805-Land	133,038	0	133,038
1806-Land Rights	0	0	0
1808-Buildings and Fixtures	7,112,389	0	7,112,389
1810-Leasehold Improvements	75,507	0	75,507
1820-Distribution Station Equipment - ARO	45,125	0	45,125
1820-Distribution Station Equipment - Normally Primary below 50 kV	8,125,921	0	8,125,921
1825-Storage Battery Equipment	0	0	0
1830-Poles, Towers and Fixtures	36,074,505	0	36,074,505
1835-Overhead Conductors and Devices	35,919,190	0	35,919,190
1840-Underground Conduit	14,109,114	0	14,109,114
1845-Underground Conductors and Devices	19,699,141	0	19,699,141
1850-Line Transformers	29,260,337	0	29,260,337
1855-Services	21,487,435	0	21,487,435
1860-Meters	9,355,717	0	9,355,717
1865-Other Installations on Customer's Premises	0	0	0
1450-Distribution Plant Total	**181,397,416**	**0**	**181,397,416**

1500-General Plant		**Non Wires**	**Consolidated**
1905-Land	0	0	0
1906-Land Rights	0	0	0
1908-Buildings and Fixtures	0	0	0
1910-Leasehold Improvements	0	0	0
1915-Office Furniture and Equipment	1,456,089	0	1,456,089
1920-Computer Equipment - Hardware	2,992,962	0	2,992,962
1925-Computer Software	1,256,733	0	1,256,733
1930-Transportation Equipment	7,140,683	0	7,140,683
1935-Stores Equipment	63,417	0	63,417
1940-Tools, Shop and Garage Equipment	2,590,157	0	2,590,157
1945-Measurement and Testing Equipment	317,274	0	317,274
1950-Power Operated Equipment	208,022	0	208,022
1955-Communication Equipment	345,245	0	345,245
1960-Miscellaneous Equipment	0	0	0
1970-Load Management Controls - Customer Premises	0	0	0
1975-Load Management Controls - Utility Premises	0	0	0
1980-System Supervisory Equipment	566,626	0	566,626
1985-Sentinel Lighting Rentals	(0)	85,872	85,872

1990-Other Tangible Property	0	0	0
1995-Contributions and Grants	(17,725,330)	0	(17,725,330)
1500-General Plant Total	**(788,123)**	**85,872**	**(702,251)**

1550-Other Capital Assets		**Non Wires**	**Consolidated**
2005-Property Under Capital Leases	0	0	0
2010-Electric Plant Purchased or Sold	0	0	0
2020-Experimental Electric Plant Unclassified	0	0	0
2030-Electric Plant and Equipment Leased to Others	0	0	0
2040-Electric Plant Held for Future Use	0	0	0
2050-Completed Construction Not Classified--Electric	0	0	0
2055-Construction Work in Progress--Electric	983,556	52,664	1,036,220
2060-Electric Plant Acquisition Adjustment	0	0	0
2065-Other Electric Plant Adjustment	0	0	0
2070-Other Utility Plant	0	0	0
2075-Non-Utility Property Owned or Under Capital Lease	0		0
1550-Other Capital Assets Total	**983,556**	**52,664**	**1,036,220**

1600-Accumulated Amortization		**Non Wires**	**Consolidated**
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(96,454,056)	(29,386)	(96,483,442)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	(179,437)	0	(179,437)
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0	0	0
2160-Accumulated Amortization of Other Utility Plant	0	0	0
2180-Accumulated Amortization of Non-Utility Property	0	0	0
1600-Accumulated Amortization Total	**(96,633,493)**	**(29,386)**	(96,662,879)

Total Assets	**116,867,531**	**(101,322)**	**116,766,209**

1650-Current Liabilities		**Non Wires**	**Consolidated**
2205-Accounts Payable	10,331,443	0	10,331,443
2208-Customer Credit Balances	769,752	0	769,752
2210-Current Portion of Customer Deposits	1,715,566	0	1,715,566
2215-Dividends Declared	0	0	0
2220-Miscellaneous Current and Accrued Liabilities	1,604,862	0	1,604,862
2225-Notes and Loans Payable	0	0	0
2240-Accounts Payable to Associated Companies	37,524	0	37,524
2242-Notes Payable to Associated Companies	0	0	0
2250-Debt Retirement Charges (DRC) Payable	504,235	0	504,235
2252-Transmission Charges Payable	0	0	0
2254-Electric Safety Authority Fees Payable	0	0	0

2256-Independent Market Operator Fees and Penalties Payable	0	0	0
2260-Current Portion of Long Term Debt	794,766	0	794,766
2262-Ontario Hydro Debt - Current Portion	0	0	0
2264-Pensions and Employee Benefits - Current Portion	0	0	0
2268-Accrued Interest on Long Term Debt	0	0	0
2270-Matured Long Term Debt	0	0	0
2272-Matured Interest on Long Term Debt	0	0	0
2285-Obligations Under Capital Leases--Current	0	0	0
2290-Commodity Taxes	(919,542)	0	(919,542)
2292-Payroll Deductions / Expenses Payable	236,548	0	236,548
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	76,335	0	76,335
2296-Future Income Taxes - Current	0	0	0
1650-Current Liabilities Total	**15,151,488**	**0**	**15,151,488**

1700-Non-Current Liabilities		**Non Wires**	**Consolidated**
2305-Accumulated Provision for Injuries and Damages	0	0	0
2306-Employee Future Benefits	2,237,536	0	2,237,536
2308-Other Pensions - Past Service Liability	0	0	0
2310-Vested Sick Leave Liability	602,654	0	602,654
2315-Accumulated Provision for Rate Refunds	0	0	0
2320-Other Miscellaneous Non-Current Liabilities (includes ARO)	917,762	0	917,762
2325-Obligations Under Capital Lease--Non-Current	0	0	0
2330-Devolpment Charge Fund	0	0	0
2335-Long Term Customer Deposits	0	0	0
2340-Collateral Funds Liability	0	0	0
2345-Unamortized Premium on Long Term Debt	0	0	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0	0	0
2350-Future Income Tax - Non-Current	(3,959,000)	0	(3,959,000)
2405-Other Regulatory Liabilities	0	0	0
2410-Deferred Gains From Disposition of Utility Plant	0	0	0
2415-Unamortized Gain on Reacquired Debt	0	0	0
2425-Other Deferred Credits	0	0	0
2440-Deferred Revenue	977,272	0	977,272
1700-Non-Current Liabilities Total	**776,225**	**0**	**776,225**

1800-Long-Term Debt		**Non Wires**	**Consolidated**
2505-Debentures Outstanding - Long Term Portion	0	0	0
2510-Debenture Advances	0	0	0
2515-Required Bonds	0	0	0
2520-Other Long Term Debt	0	0	0
2525-Term Bank Loans - Long Term Portion	17,634,066	0	17,634,066
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0	0	0

2550-Advances from Associated Companies	31,452,941	0	31,452,941
1800-Long-Term Debt Total	**49,087,007**	**0**	**49,087,007**

1850-Shareholders' Equity		**Non Wires**	**Consolidated**
3005-Common Shares Issued	21,899,072	0	21,899,072
3008-Preference Shares Issued	0	0	0
3010-Contributed Surplus	2,037,559	0	2,037,559
3020-Donations Received	0	0	0
3022-Devolpment Charges Transferred to Equity	0	0	0
3026-Capital Stock Held in Treasury	0	0	0
3030-Miscellaneous Paid-In Capital	13,032,554	0	13,032,554
3035-Installments Received on Capital Stock	0	0	0
3040-Appropriated Retained Earnings	0	0	0
3045-Unappropriated Retained Earnings	13,183,880		13,183,880
3046-Balance Transferred From Income	1,699,746	(101,322)	1,598,424
3047-Appropriations of Retained Earnings - Current Period	0	0	0
3048-Dividends Payable-Preference Shares	0	0	0
3049-Dividends Payable-Common Shares	0	0	0
3055-Adjustment to Retained Earnings	0	0	0
3065-Unappropriated Undistributed Subsidiary Earnings	0	0	0
1850-Shareholders' Equity Total	**51,852,811**	**(101,322)**	**51,751,489**

Total Liabilities & Shareholder's Equity	**116,867,531**	**(101,322)**	**116,766,209**

Balance Sheet Total	0	0	0

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Thunder Bay Hydro Electricity Distribution Inc.
, License Number ED-2002-0529, File Number EB-2012-0167

Thunder Bay Hydro Electricity Distribution Inc.
2013 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total	Total	Total
3000-Sales of Electricity		**Non Wires**	**Consolidated**
4006-Residential Energy Sales	(24,995,249)	0	(24,995,249)
4010-Commercial Energy Sales	0	0	0
4015-Industrial Energy Sales	0	0	0
4020-Energy Sales to Large Users	0	0	0
4025-Energy Sales to Street Lights	(934,518)	0	(934,518)
4030-Energy Sales to Sentinel Lighting	(10,152)		(10,152)
4035-General Energy Sales	(45,301,056)	0	(45,301,056)
4040-Other Energy Sales to Public Authorities	0	0	0
4045-Energy Sales to Railroads and Railways	0	0	0
4050-Revenue Adjustment	(1,372,557)	0	(1,372,557)
4055-Energy Sales for Resale	(6,986,190)	0	(6,986,190)
4060-Interdepartmental Energy Sales	(205,000)	0	(205,000)
4062-WMS	(6,165,444)	0	(6,165,444)
4064-Billed WMS-One Time	0	0	0
4066-NS	(6,377,956)	0	(6,377,956)
4068-CS	(4,672,317)	0	(4,672,317)
4075-LV Charges	0	0	0
3000-Sales of Electricity Total	**(97,020,439)**	**0**	**(97,020,439)**
3050-Revenues From Services - Distribution		**Non Wires**	**Consolidated**
4080-Distribution Services Revenue	(19,901,055)	0	(19,901,055)
4080-2-SSS Revenue	(131,340)	0	(131,340)
4082-RS Rev	(59,150)	0	(59,150)
4084-Serv Tx Requests	(1,900)	0	(1,900)
4080-3-One Time Distribution Revenues	700,106	0	700,106
3050-Revenues From Services - Distribution Total	**(19,393,339)**	**0**	**(19,393,339)**
3100-Other Operating Revenues		**Non Wires**	**Consolidated**
4205-Interdepartmental Rents	0	0	0
4210-Rent from Electric Property	(471,000)	(6,000)	(477,000)
4215-Other Utility Operating Income	0	0	0
4220-Other Electric Revenues	(180,818)	0	(180,818)
4225-Late Payment Charges	(297,000)	0	(297,000)
4230-Sales of Water and Water Power	0	0	0
4235-Miscellaneous Service Revenues	(267,807)	0	(267,807)
4240-Provision for Rate Refunds	0	0	0

4245-Government Assistance Directly Credited to Income	(12,712)	0	(12,712)
3100-Other Operating Revenues Total	**(1,229,337)**	**(6,000)**	**(1,235,337)**

3150-Other Income & Deductions		**Non Wires**	**Consolidated**
4305-Regulatory Debits	0	0	0
4310-Regulatory Credits	0	0	0
4315-Revenues from Electric Plant Leased to Others	0	0	0
4320-Expenses of Electric Plant Leased to Others	0	0	0
4324-SPC Recovery	0	0	0
4325-Revenues from Merchandise, Jobbing, Etc.	0	0	0
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0	0	0
4335-Profits and Losses from Financial Instrument Hedges	0	0	0
4340-Profits and Losses from Financial Instrument Investments	0	0	0
4345-Gains from Disposition of Future Use Utility Plant	0	0	0
4350-Losses from Disposition of Future Use Utility Plant	0	0	0
4355-Gain on Disposition of Utility and Other Property	14,120	0	14,120
4362-Loss from Retirement of Utility and Other Property	30,000	0	30,000
4365-Gains from Disposition of Allowances for Emission	0	0	0
4370-Losses from Disposition of Allowances for Emission	0	0	0
4375-Revenues from Non-Utility Operations	(668,839)	0	(668,839)
4380-Expenses of Non-Utility Operations	677,101	94,443	771,544
4385-Expenses of Non-Utility Operations	0	0	0
4390-Miscellaneous Non-Operating Income	(272,000)	0	(272,000)
4395-Rate-Payer Benefit Including Interest	0	0	0
4398-Foreign Exchange Gains and Losses, Including Amortization	0	0	0
3150-Other Income & Deductions Total	**(219,618)**	**94,443**	**(125,175)**

3200-Investment Income		**Non Wires**	**Consolidated**
4405-Interest and Dividend Income	(110,390)	0	(110,390)
4415-Equity in Earnings of Subsidiary Companies	0	0	0
3200-Investment Income Total	**(110,390)**	**0**	**(110,390)**

3350-Power Supply Expenses		**Non Wires**	**Consolidated**
4705-Power Purchased	79,603,504	0	79,603,504
4708-WMS	6,189,789	0	6,189,789
4710-Cost of Power Adjustments	0	0	0
4712-0	0	0	0
4714-NW	6,450,150	0	6,450,150
4715-System Control and Load Dispatching	0	0	0
4716-NCN	4,776,996	0	4,776,996
4720-Other Expenses	0	0	0
4725-Competition Transition Expense	0	0	0

4730-Rural Rate Assistance Expense	0	0	0
4750-LV Charges	0	0	0
3350-Power Supply Expenses Total	**97,020,439**	**0**	**97,020,439**

3500-Distribution Expenses - Operation		**Non Wires**	**Consolidated**
5005-Operation Supervision and Engineering	580,788	0	580,788
5010-Load Dispatching	785,902	0	785,902
5012-Station Buildings and Fixtures Expense	339,979	0	339,979
5014-Transformer Station Equipment - Operation Labour	0	0	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	0	0	0
5016-Distribution Station Equipment - Operation Labour	0	0	0
5017-Distribution Station Equipment - Operation Supplies and Expenses	86,126	0	86,126
5020-Overhead Distribution Lines and Feeders - Operation Labour	273,101	0	273,101
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	778,605	0	778,605
5030-Overhead Subtransmission Feeders - Operation	0	0	0
5035-Overhead Distribution Transformers - Operation	200,782	0	200,782
5040-Underground Distribution Lines and Feeders - Operation Labour	44,699	0	44,699
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	24,150	0	24,150
5050-Underground Subtransmission Feeders - Operation	0	0	0
5055-Underground Distribution Transformers - Operation	186,171	0	186,171
5060-Street Lighting and Signal System Expense	0	0	0
5065-Meter Expense	232,948	0	232,948
5070-Customer Premises - Operation Labour	1,355	0	1,355
5075-Customer Premises - Materials and Expenses	13,572	0	13,572
5085-Miscellaneous Distribution Expense	11,526	0	11,526
5090-Underground Distribution Lines and Feeders - Rental Paid	0	0	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	0	0	0
5096-Other Rent	0	0	0
3500-Distribution Expenses - Operation Total	**3,559,704**	**0**	**3,559,704**

3550-Distribution Expenses - Maintenance		**Non Wires**	**Consolidated**
5105-Maintenance Supervision and Engineering	957,979	0	957,979
5110-Maintenance of Structures	16,185	0	16,185
5112-Maintenance of Transformer Station Equipment	0	0	0
5114-Mtaint Dist Stn Equip	236,785	0	236,785
5120-Maintenance of Poles, Towers and Fixtures	202,530	0	202,530
5125-Maintenance of Overhead Conductors and Devices	961,649	0	961,649
5130-Maintenance of Overhead Services	358,829	0	358,829
5135-Overhead Distribution Lines and Feeders - Right of Way	744,289	0	744,289
5145-Maintenance of Underground Conduit	29,729	0	29,729

5150-Maintenance of Underground Conductors and Devices	137,629	0	137,629
5155-Maintenance of Underground Services	179,003	0	179,003
5160-Maintenance of Line Transformers	127,355	0	127,355
5165-Maintenance of Street Lighting and Signal Systems	0	0	0
5170-Sentinel Lights - Labour	0	8,767	8,767
5172-Sentinel Lights - Materials and Expenses	0	0	0
5175-Maintenance of Meters-Smart Meter LTD 2009-2011 Costs here	0	0	0
5178-Customer Installations Expenses - Leased Property	0	0	0
5195-Maintenance of Other Installations on Customer Premises	0	0	0
3550-Distribution Expenses - Maintenance Total	**3,951,962**	**8,767**	**3,960,729**

3650-Billing and Collecting		**Non Wires**	**Consolidated**
5305-Supervision	0	0	0
5310-Meter Reading Expense	293,296	0	293,296
5315-Customer Billing	1,197,595	0	1,197,595
5320-Collecting	513,803	0	513,803
5325-Collecting - Cash Over and Short	0	0	0
5330-Collection Charges	0	0	0
5335-Bad Debt Expense	130,000	0	130,000
5340-Miscellaneous Customer Accounts Expenses	0	0	0
3650-Billing and Collecting Total	**2,134,694**	**0**	**2,134,694**

3700-Community Relations		**Non Wires**	**Consolidated**
5405-Supervision	0	0	0
5410-Community Relations - Sundry	0	0	0
5415-Energy Conservation	110,062	0	110,062
5420-Community Safety Program	31,800	0	31,800
5425-Miscellaneous Customer Service and Informational Expenses	0	0	0
3700-Community Relations Total	**141,862**	**0**	**141,862**

Sales Expenses		**Non Wires**	**Consolidated**
5505-Supervision	0	0	0
5510-Demonstrating and Selling Expense	0	0	0
5515-Advertising Expense	120,271	0	120,271
5520-Miscellaneous Sales Expense	0	0	0
-Administrative and General Expenses	0	0	0
Sales Expenses Total	**120,271**	**0**	**120,271**

3800-Administrative and General Expenses		**Non Wires**	**Consolidated**
5605-Executive Salaries and Expenses	914,411	0	914,411
5610-Management Salaries and Expenses	0	0	0
5615-General Administrative Salaries and Expenses	1,414,365	0	1,414,365

5620-Office Supplies and Expenses	296,300	0	296,300
5625-Administrative Expense Transferred-Credit	0	0	0
5630-Outside Services Employed	208,800	0	208,800
5635-Property Insurance	31,328	0	31,328
5640-Injuries and Damages	281,747	0	281,747
5645-Employee Pensions and Benefits	897,374	0	897,374
5650-Franchise Requirements	0	0	0
5655-Regulatory Expenses	181,300	0	181,300
5660-General Advertising Expenses	0	0	0
5665-Miscellaneous Expenses	145,972	0	145,972
5670-Rent	291,905	0	291,905
5675-Maintenance of General Plant	86,220	0	86,220
5680-Electrical Safety Authority Fees	0	0	0
5681-SPC Expense	0	0	0
5685-Independent Market Operator Fees and Penalties	0	0	0
5695-OM&A Contra Account	0	0	0
3800-Administrative and General Expenses Total	**4,749,722**	**0**	**4,749,722**

3850-Amortization Expense		**Non Wires**	**Consolidated**
5705-Amortization Expense - Property, Plant and Equipment	3,204,833	4,112	3,208,945
5710-Amortization of Limited Term Electric Plant	0	0	0
5715-Amortization of Intangibles and Other Electric Plant	42,411	0	42,411
5720-Amortization of Electric Plant Acquisition Adjustments	0	0	0
5725-Miscellaneous Amortization		0	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0	0	0
5735-Amortization of Deferred Development Costs	0	0	0
5740-Amortization of Deferred Charges	0	0	0
3850-Amortization Expense Total	**3,247,244**	**4,112**	**3,251,356**

3900-Interest Expense		**Non Wires**	**Consolidated**
6005-Interest on Long Term Debt	630,481	0	630,481
6010-Amortization of Debt Discount and Expense	0	0	0
6015-Amortization of Premium on Debt-Credit	0	0	0
6020-Amortization of Loss on Reacquired Debt	0	0	0
6025-Amortization of Gain on Reacquired Debt-Credit	0	0	0
6030-Interest on Debt to Associated Companies	0	0	0
6035-Other Interest Expense	119,298	0	119,298
6040-Allowance for Borrowed Funds Used During Construction-Credit	0	0	0
6042-Allowance for Other Funds Used During Construction	0	0	0
6045-Interest Expense on Capital Lease Obligations	0	0	0
3900-Interest Expense Total	**749,779**	**0**	**749,779**

3950-Taxes Other Than Income Taxes		Non Wires	Consolidated
6105-Taxes Other Than Income Taxes	0	0	0
3950-Taxes Other Than Income Taxes Total	**0**	**0**	**0**

4000-Income Taxes		Non Wires	Consolidated
6110-Income Taxes	0	0	0
6115-Provision for Future Income Taxes	573,500	0	573,500
4000-Income Taxes Total	**573,500**	**0**	**573,500**

4100-Extraordinary & Other Items		Non Wires	Consolidated
6205-Donations	24,200	0	24,200
6210-Life Insurance	0	0	0
6215-Penalties	0	0	0
6225-Other Deductions	0	0	0
4100-Extraordinary & Other Items Total	**24,200**	**0**	**24,200**

Net Income - (Gain)/Loss	**(1,699,746)**	**101,322**	**(1,598,424)**

APPENDIX 1-E

Copy of
Thunder Bay Hydro Corporation
Audited Financial Statements for the Year Ended December 31, 2011

Consolidated Financial Statements

Thunder Bay Hydro Corporation

December 31, 2011

Thunder Bay Hydro Corporation

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BDO Canada LLP
1095 Barton Street
Thunder Bay ON P7B 5N3 Canada

Independent Auditor's Report

To the Shareholder of
Thunder Bay Hydro Corporation

We have audited the accompanying consolidated financial statements of Thunder Bay Hydro Corporation, which comprise the consolidated balance sheet as at December 31, 2011, and the consolidated statements of operations and retained earnings and consolidated statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

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

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers 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 presentation of the consolidated financial statements.

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

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Thunder Bay Hydro Corporation 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.

BDO Canada LLP, a Canadian limited liability partnership, is a member of BDO International Limited, a UK company limited by guarantee, and forms part of the international BDO network of independent member firms.

BDO

Independent Auditor's Report (cont'd)

Other Matters
The consolidated financial statements of Thunder Bay Hydro Corporation for the year ended December 31, 2010, were reported on under an unqualified independent auditor's report dated April 13, 2011 by another public accounting firm.

BDO Canada LLP

Chartered Accountants, Licensed Public Accountants

Thunder Bay, Ontario
April 26, 2012

Thunder Bay Hydro Corporation
Consolidated Balance Sheet

As at December 31	**2011**	2010
	$	$
ASSETS		
Current		
Cash	**13,635,126**	10,351,989
Investments	**32,025**	3,890,603
Accounts receivable *[note 16]*	**9,434,424**	8,008,296
Unbilled revenue *[note 16]*	**13,517,342**	11,589,843
Payments in lieu of corporate income taxes receivable	**95,036**	1,595,317
Due from related party *[note 15]*	**-**	52,813
Stores inventory	**1,343,307**	1,303,372
Prepaid expenses	**297,340**	207,245
Total current assets	**38,354,600**	36,999,478
Other		
Intangible assets *[note 2]*	**1,246,715**	1,278,115
Regulatory assets *[note 3]*	**8,303,200**	8,202,090
Future tax asset *[note 4]*	**7,009,840**	6,613,000
Total other assets	**16,559,755**	16,093,205
Property, plant and equipment, at cost		
Property, plant and equipment, net *[note 5[a]]*	**84,879,233**	81,174,156
Capital contributions, net *[note 5[b]]*	**(12,634,977)**	(10,305,020)
Construction-in-progress	**3,002,923**	1,758,058
Property, plant and equipment, net	**75,247,179**	72,627,194
	130,161,534	125,719,877

The accompanying notes are an integral part of these financial statements

On behalf of the Board:

Director

Director

	2011	2010
	$	$
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable and accrued liabilities	**13,254,539**	12,984,906
Debt retirement charges payable	**504,235**	533,626
Deferred revenue and contributions	**620,352**	182,080
Due to related party *[note 15]*	**13,858**	-
Customer deposits	**2,261,858**	3,059,521
Current portion of long-term debt *[note 7]*	**872,625**	831,406
Total current liabilities	**17,527,467**	17,591,539
Long-term		
Regulatory liabilities *[note 3]*	**5,091,445**	2,874,839
Employee future benefits liability *[note 8]*	**2,792,159**	2,858,140
Note payable to City of Thunder Bay *[note 9]*	**34,931,625**	34,931,625
Accrued liabilities	**159,907**	37,610
Asset retirement obligation *[note 10]*	**91,160**	118,118
Long-term debt *[note 7]*	**15,058,566**	15,928,089
Future tax liability *[note 4]*	**2,549,865**	2,081,000
Total long-term liabilities	**60,674,727**	58,829,421
Shareholder's equity		
Share capital		
Authorized		
Unlimited common shares		
Issued		
1,000 common shares	**34,931,625**	34,931,625
Retained earnings	**17,027,715**	14,367,292
Total shareholder's equity	**51,959,340**	49,298,917
	130,161,534	125,719,877

Thunder Bay Hydro Corporation
Consolidated Statement of Operations and Retained Earnings

Year ended December 31	2011	2010
	$	$
REVENUES AND FLOW-THROUGH CHARGES		
Flow-through charges plus distribution revenues	**103,377,657**	95,171,784
Flow-through costs of energy	**(85,875,693)**	(78,674,166)
Distribution revenue	**17,501,964**	16,497,618
Other operating revenue *[note 11]*	**5,268,789**	3,399,821
	22,770,753	19,897,439
EXPENSES		
Administration *[schedule]*	**5,390,068**	5,518,079
Amortization *[note 12]*	**5,009,980**	4,695,612
Operations and maintenance *[schedule]*	**6,717,973**	6,939,923
Provision for payments in lieu of capital tax	**3,752**	69,700
Utility services *[schedule]*	**412,952**	430,981
Plant operations	**1,089,993**	348,212
Recoverable expenses	**63,710**	42,575
	18,688,428	18,045,082
Earnings before the following	**4,082,325**	1,852,357
Interest on long-term debt	**802,253**	419,634
Carrying charges on regulatory assets/liabilities, net	**(261,851)**	(44,733)
Earnings before provision for taxes	**3,541,923**	1,477,456
Payments in lieu of corporate income taxes *[note 4]*		
Current	**793,675**	742,500
Future	**87,825**	(295,000)
	881,500	447,500
Earnings for the year	**2,660,423**	1,029,956
Retained earnings, beginning of year	**14,367,292**	13,337,336
Retained earnings, end of year	**17,027,715**	14,367,292

The accompanying notes are an integral part of these financial statements

Thunder Bay Hydro Corporation
Consolidated Statement of Cash Flows

Year ended December 31	2011	2010
	$	$
OPERATING ACTIVITIES		
Earnings for year from continuing operations	**2,660,423**	1,029,956
Add charges (deduct credits) to operations not involving a current payment (receipt) of cash		
Accretion expense related to asset retirement obligation	**5,119**	(9,063)
Amortization *[note 12]*	**5,931,145**	5,520,390
Amortization of capital contributions *[note 12]*	**(628,096)**	(509,632)
Amortization of intangible assets *[note 12]*	**71,717**	65,561
(Decrease) increase in employee future benefits liability	**(65,981)**	54,216
Gain on disposal of property, plant and equipment	**(25,451)**	(400)
Future income taxes	**72,025**	(295,000)
	8,020,901	5,856,028
Net change in non-cash working capital balances related to operations *[note 14[a]]*	**(2,035,854)**	(1,691,739)
Cash provided by operating activities	**5,985,047**	4,164,289
INVESTMENT ACTIVITIES		
Proceeds on sale of property, plant and equipment	**27,075**	400
Additions to intangible assets	**(40,317)**	(392,296)
Additions to property, plant and equipment, net *[note 14[b]]*	**(7,899,658)**	(6,930,538)
Sale (purchase) of investments	**3,858,578**	(77,966)
Cancellation of share capital	**-**	(1)
Cash used in investment activities	**(4,054,322)**	(7,400,401)
FINANCING ACTIVITIES		
(Increase) decrease in regulatory assets	**(101,110)**	798,428
Increase (decrease) in regulatory liabilities	**2,216,606**	(1,158,269)
Increase in due to related party	**122,297**	37,610
Proceeds on financing, net	**-**	3,826,751
Repayment of long-term debt	**(828,304)**	(367,673)
Unapplied loan proceeds - restricted cash	**(25,000)**	(387,474)
Non-cash stranded asset cost included in regulatory assets	**-**	221,401
ARO liabilities settled during the year	**(32,077)**	(47,495)
Cash provided by financing activities	**1,352,412**	2,923,279
Increase (decrease) in cash during the year	**3,283,137**	(312,833)
Cash, beginning of year	**10,351,989**	10,664,822
Cash, end of year	**13,635,126**	10,351,989

The accompanying notes are an integral part of these financial statements

GENERAL

Thunder Bay Hydro Corporation ("the Corporation") is a wholly-owned subsidiary of The Corporation of the City of Thunder Bay providing electrical distribution services as regulated by the Ontario Energy Board ("OEB"), to inhabitants of the City of Thunder Bay and the Fort William First Nation Reserve. It also provides meter services to various corporations in Northwestern Ontario as well as administrative and billing services for other utilities in Northwestern Ontario. The Corporation also operates a landfill gas generation plant under a 20-year contract with the Ontario Power Authority ("OPA") effective August, 2010.

The Consolidated statements include the accounts of the Corporation and its wholly-owned subsidiaries:

Thunder Bay Hydro Electricity Distribution Inc. ("TBHEDI")
Thunder Bay Hydro Utility Services Inc. ("TBHUSI")
Thunder Bay Hydro Renewable Power Incorporated ("TBHRPI")

All intercompany balances and transactions have been eliminated.

1. SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and reflect the significant accounting policies summarized below.

International Financial Reporting Standards

The Corporation did not adopt IFRS for the year ended December 31, 2011 as the mandatory adoption for entities with activities subject to rate regulation was deferred to fiscal years beginning on or after January 1, 2012. The Accounting Standards has recently decided that the mandatory adoption of IFRS for such entities will be deferred an additional year. The Corporation is still considering its options and has not yet decided whether it will adopt IFRS in 2012 or 2013.

Rate setting and regulation

The rates of the Corporation's electricity distribution are subject to regulation by the OEB. The cost of power and all costs other than distribution related to the operations of the electricity grid including transmission, connection and administration costs are flowed through to the consumer.

The distribution revenue is designed to recover the costs incurred by the Corporation in delivering electricity to customers. Distribution rates are regulated by the OEB and typically comprise a monthly service charge and a volumetric charge.

Stores inventory

Stores inventory consists principally of maintenance and construction materials and is valued at the lower of cost and net realizable value. Cost is determined using the average cost method.

Property, plant and equipment

Property, plant and equipment are stated at cost less accumulated amortization. Gains or losses on retirement or disposition of assets which are not grouped are credited or charged to other operating revenue. Amortization is provided on a straight-line basis for property, plant and equipment over their estimated service lives at the following annual rates:

Buildings	2%
Distribution and transformation equipment	3% to 4%
Other assets	10% to 20%
Rolling stock	12½% to 20%
Generation assets	15 to 75 years

Spare Transformers and Meters

Spare transformers and meters are held to back up plant in service and are expected to substitute for original distribution plant transformers and meters when these original plant assets are being repaired. According to the criteria prescribed by the OEB in the Accounting Procedures Handbook the spare transformers and meters are treated as property, plant and equipment. Under Canadian GAAP for unregulated businesses the spare transformers and meters would be treated as inventory.

Intangible assets

Intangible assets represent computer applications software and capital contributions. These assets are carried at cost net of accumulated amortization.

Amortization is provided on a straight-line basis for intangible assets over their estimated useful lives at the following rates:

Computer software	20%
Capital contributions	4%

Regulated Assets and Liabilities

The company has adopted the CICA's Accounting Guideline 19 "Disclosures by Entities Subject to Rate Regulation". Based on OEB regulations, certain costs and variance account balances are recorded as regulatory liabilities and are reflected in the balance sheet until the OEB determines the manner and timing of their disposition.

Regulatory assets represent future revenues associated with certain costs, incurred in the

current period or in prior period(s), that are expected to be recovered from consumers in future periods through the rate-setting process. Regulatory liabilities represent future expenses associated with the collection of certain revenues, earned in the current period or in prior period(s), that are expected to be returned to consumers in future periods through the rate-setting process. Regulatory assets and liabilities can arise from differences in amounts collected from customers (based on regulated rates) and the corresponding costs of non-competitive electricity service incurred by the Corporation in the wholesale market administered by the Independent Electricity System Operator (the "IESO") after May 1, 2002.

These amounts have been accumulated pursuant to regulation underlying the Electricity Act (the "EA") and deferred in anticipation of their future recovery or expense in electricity distribution service charges. In the absence of rate regulation, these rate regulated assets and liabilities would be recognized in income in the period to which they relate. See Note 3 for further details.

Pension plan

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 *[note 13]*. The Corporation recognizes the expense related to this plan as contributions are made.

Other post-employment benefits

Employee future benefits provided by the Corporation include medical and life insurance benefits and accumulated sick leave credits. These plans provide benefits to certain employees when they are no longer providing active service. Employee future benefit expense is recognized in the period in which the employees render the services. Employee future benefits are recorded on an accrual basis. The accrued benefit obligations and current service cost are calculated using the projected benefit method pro-rated on service and based on assumptions that reflect management's best estimate. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered in the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. Actuarial gains (losses) are amortized into expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effects of a curtailment gain or loss are recognized in earnings in the year of the event giving rise to the curtailment. The effects of a settlement gain or loss are recognized in earnings for the period in which a settlement occurs.

Revenue recognition

Distribution revenue is recognized on the basis of regular meter readings. Estimates of customer usage since the last meter reading date, to the end of the year are recorded as unbilled revenue.

Pole line revenue is recognized based on annual contracted rates and agreed-upon pole counts.

The Corporation has entered into Conservation Demand Management ("CDM") agreements with the OPA for the period from 2011 to 2015. Performance, management and incentive fees are recognized according to the applicable OPA service agreements.

Revenues from Lost Revenue Adjustment Mechanism and Shared Savings Mechanism approved in rates are recognized on an accrual basis.

The Ontario Power Authority Renewable Energy Standard Offer Program ("RESOP") contract revenue is recognized based on the contract price and the hourly generation for the month.

Other revenue is recognized when the requirements as to performance for transactions involving the sale of goods or services are met and ultimate collection is reasonably assured at the time of performance.

Construction-in-progress

Construction-in-progress is comprised of the costs of assets not yet placed into service, assets under construction, and pre-construction activities related to projects expected to be completed. These amounts are not amortized. Upon energization of assets, the amounts are transferred to property, plant and equipment and are amortized on a straight-line basis over the expected service life of the asset.

Contributions in aid of construction

Capital contributions are required contributions received from outside sources, used to finance additions to property, plant and equipment. Capital contributions are credited against property, plant and equipment. The amount is subsequently amortized by a charge to accumulated amortization and a credit to amortization expense, at an equivalent rate to that used for the amortization of the related property, plant and equipment.

Customer deposits

Customers' advance deposits are cash collections from customers or Energy Retailers to guarantee the payment of energy related bills. The deposits bear interest at prime less 2% and is paid annually to customers.

Customer deposits also include collections from renewable generation customers for connection cost and capacity allocation deposits, as dictated by the OPA and

contributions in aid of construction on construction projects which have not been completed or capitalized during the year. Interest may be payable on the capacity allocation deposit upon connection of the renewable generation facility. Interest is not payable on contributions in aid of construction.

Use of estimates and measurement uncertainty

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes as well as the disclosure of contingent assets and liabilities at the financial statement date.

Accounts receivable, unbilled service revenue, regulatory assets, regulatory liabilities and employee future benefits are reported based on amounts expected to be recovered or incurred and reflect an appropriate allowance for unrecoverable amounts based on management's estimates. Amounts recorded for amortization of property, plant and equipment are based on estimates of useful service life.

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

Corporate income taxes and capital taxes

The current tax-exempt status of the Corporation under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) reflects the fact that the Corporation is wholly-owned by a municipality. This tax-exempt status might be lost in a number of circumstances, including if the municipality ceases to own 90% or more of the shares or capital of the Corporation, or if a non-government entity has rights immediately or in the future, either absolutely or contingently, to acquire more than 10% of the shares of the Corporation.

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate taxes ("PILS") to the Ontario Electricity Financing Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at amounts receivable or payable from/to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they will be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

Asset retirement obligation

The Corporation recognizes a liability for the future removal and handling cost for contamination in distribution equipment and units in storage. Initially, the liability is measured at present value and the amount of the liability is added to the carrying amount of the related asset. In subsequent periods, the asset is amortized and the liability is adjusted annually for the discount applied upon initial recognition of the liability ("accretion expense") and for changes in the underlying assumptions. The liability is recognized when the asset retirement obligation ("ARO") is incurred and when the fair value is determined.

Financial instruments

On initial recognition, all financial instruments which meet the definition of a financial asset or financial liability are to be recorded at fair value, unless fair value cannot be reliably determined. Depending on the nature of the financial instrument, revenues, expenses, gains and losses would be reported in either net income or other comprehensive income. Subsequent measurement of each financial instrument will depend on the balance sheet classification elected by the Corporation. The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between willing parties.

The Corporation classifies its financial instruments as follows and uses the following methods and assumptions to estimate the fair value of each class of financial instrument for which carrying amounts are included in the Consolidated Balance Sheet:

- Cash is classified as "Held-for-Trading" and is measured at fair value.
- Investments comprising short-term investments are classified as "Held-for-Trading"

and are measured at fair value.

- Accounts receivable are classified as "Loans and Receivables" and are measured at amortized cost, which upon initial recognition, is considered equivalent to fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Accounts payable and accrued liabilities are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method.
- Customer deposits are classified as "Other Financial Liabilities" and are initially measured at their fair value. Subsequent measurements are recorded at amortized cost using the effective interest rate method. The carrying amounts approximate fair value because of the short maturity.
- Note payable to the City of Thunder Bay is classified as "Other Financial Liabilities" and are intially measured at cost.
- Long-term debt is classified as "Other Financial Liabilities" and was initially measured at cost. Subsequent measurements are recorded at amortized cost using the effective interest method.

2. INTANGIBLE ASSETS

Details of year-end intangible asset balances are as follows:

	2011		2010	
	Cost	**Accumulated amortization**	Cost	Accumulated amortization
	$	$	$	$
Computer software	**819,829**	**759,302**	779,512	738,478
Capital contributions to Hydro One for wholesale meters	**1,272,321**	**86,133**	1,272,321	35,240
	2,092,150	**845,435**	2,051,833	773,718
Intangible assets, net	**1,246,715**		1,278,115	

See note 12 for details of the amortization for the year.

3. REGULATORY ASSETS (LIABILITIES)

	2011 $	2010 $
Regulatory Assets		
Deferral for cash pension contributions	**474**	474
Deferral for OEB annual cost assessment	**121**	121
Special purpose charge	**34,581**	-
Deferral of IFRS implementation costs	**51,295**	8,301
Recovery/repayment of regulatory balances	**864,030**	165,588
	950,501	174,484
Retailer Cost Variance	**281,283**	211,621
Smart Meter deferral	**7,071,416**	7,815,985
Regulatory Assets	**8,303,200**	8,202,090
Regulatory Liabilities		
PILS deferral	**(706,546)**	(1,646,222)
Recovery/Repayment of regulatory balances	**-**	(627,139)
	(706,546)	(2,273,361)
Wholesale market services	**(2,521,861)**	(1,643,018)
Network transmission services	**(114,563)**	629,612
Connection transmission charges	**(412,480)**	798,937
Commodity	**(1,335,995)**	(387,009)
Retail settlement variances	**(4,384,899)**	(601,478)
Regulatory Liabilities	**(5,091,445)**	(2,874,839)

In the absence of rate regulation, carrying charges on regulatory assets and liabilities would have increased by $261,851 [2010 - increased by $44,733] (see Consolidated Statement of Operations and Retained Earnings).

The regulatory asset and liability balances attract carrying charges at OEB prescribed rates and are defined as follows:

[a] Recovery/Repayment of regulatory balances

2011 OEB Approved

OEB approved balances of regulatory accounts as at December 31, 2009, including carrying charges on such balances to April 30, 2011, which were transferred to this account for disposition. The net asset entry closing the asset and liability accounts amounted to $2,725,159. Distribution rate rider amounts are credited/debited to this account as are OEB prescribed carrying charges.

[b] Retail settlement variance accounts

These balances represent the variances between the flow-through amounts charged by the Corporation to customers (based on regulated rates) and the corresponding cost of non-competitive electricity service incurred since January 1, 2009, as balances to December 31, 2008 were closed to Recovery/Repayment of regulatory balance accounts.

The OEB reviews Retail Settlement Variances quarterly for commodity and annually for non-commodity, for dispositions.

[c] Retail cost variance accounts

As per the criteria in the Accounting Procedures Handbook, the Corporation defers the net costs of services relating to the supply of competitive electricity to retailer customers since January 1, 2008, as balances to December 31, 2007 were closed to Recovery/Repayment of regulatory balance accounts.

In the absence of rate regulation, expenses in 2011 would have been $66,164 higher [2010 - $49,451].

[d] Smart Meter deferrals

The OEB approved a Smart Meter rate adder of $1.97 [2010 - $1.97] per meter and has directed Local Distribution Companies ("LDC's") to defer this seed funding along with costs incurred in implementing the government's Smart Meter Initiative. Funding deferred in the current year amount to $1,170,991 [2010 - $1,153,223]. As at December 31, 2011, Smart Meter capital expenditures, net of accumulated depreciation, totalling $6,816,013 [2010 - $7,166,274] have been recorded to a regulatory asset. These expenditures would otherwise have been recorded as property, plant and equipment and intangible assets under Canadian GAAP for unregulated businesses. In the absence of rate regulation, property, plant and equipment and intangible assets would have been $6,732,577 and $153,436 higher [2010 - $6,992,051 and $174,223 respectively].

For the year ended December 31, 2011, Smart Meter operating expenses of $328,973 [2010 - $196,573], and Smart Meter depreciation expense of $521,005 [2010 - $502,784] were deferred which would have been expensed under Canadian GAAP for unregulated businesses.

The Corporation has deferred the loss on disposition for the applicable residential and small business meters which have been removed and replaced with Smart Meters. This stranded asset cost of $nil [2010 - $221,401] would have been expensed under Canadian GAAP for unregulated businesses. The stranded asset cost and distribution revenue have been reduced by the amount of funding in current rates for depreciation on these assets in the amount of $226,017 [2010 - $238,814].

[e] Special Purpose Charge

This balance represents the amount remitted to the Ministry of Finance for the Corporation's Special Purpose Charge Assessment amount net of the amounts recovered from customers on account of the assessment. Carrying charges are calculated on the monthly opening balance at the OEB prescribed interest rate.

In the absence of rate regulation, revenues would have been increased by $172,690 [2010 - $223,631] and expenses would have increased by $nil [2010 - $389,289].

[f] Deferral of International Financial Reporting Standards ("IFRS") Implementation Costs

The OEB has approved a deferral account to record one-time administrative incremental IFRS transition costs, which are not already recovered in distribution rates.

In the absence of rate regulation, expenses would have been $42,993 higher [2010 - $8,301].

[g] Payment in Lieu of Taxes (PIL's")

On November 28, 2008, the OEB commenced a combined proceeding to determine the accuracy of the final account balances with respect to Account 1562 Deferred Payments in Lieu of Taxes ("PILs") for the period October 1, 2001 to April 30, 2006. A

decision was issued June 24, 2011 which included direction to all other distributors. "Each remaining distributor will be expected to apply for final disposition of account 1562 with its next general rates application (either IRM or cost of service). If the distributor files evidence in accordance with all the various decisions made in the course of this proceeding, including the use of the updated model of referenced above and certifies to that effect, the distributor may expect that the determination of the final account balance will be handled expeditiously and in largely administrative manner." The Corporation received a Decision and Order for final disposition with the 2012 IRM Application for rates effective May 1, 2012. The Corporation's distribution revenue has been reduced by approximately $760,000 and net carrying charges have been reduced by approximately $196,000 as a result of the decision. The adjustments were mainly reversing previously "trued-up" items with respect to regulatory asset movements (given the closing of the account causing incomplete cycle of the movements) and inclusion of the OEB approved PILs proxies during the rate freeze period imposed by Bill 210 in 2002.

4. CORPORATE INCOME AND CAPITAL TAXES

The provision for payments in lieu of corporate income and capital taxes differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate.

The impact of differences between the Corporation's reported income tax expense on operating income and the expense that would otherwise result from the application of statutory rates is as follows:

	2011	2010
	$	$
Earnings before provision for taxes	**3,541,923**	1,477,456
Statutory Canadian federal and provincial income tax rate (%)	**28.25**	30.99
Expected provision	**1,000,593**	457,864
Apprenticeship tax credit	**(75,957)**	(70,825)
Ontario small business deduction	**(36,240)**	-
Employee future benefits	**(16,831)**	(2,127)
Asset retirement obligation	**(2,322)**	87,032
Non-capital losses carried forward	**72,320**	(31,439)
Smart meter deferral	**87,930**	547,593
Capital cost in excess of amortization	**(158,845)**	(626,515)
Reserves, deductible for tax on a different basis	**4,049**	2,155
Rate adjustments	**(3,213)**	2,995
Permanent difference	**10,016**	80,767
	881,500	447,500
Effective tax rate (%)	**24.88**	30.29

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

	2011 $	2010 $
Property, plant and equipment and intangible assets	**4,908,742**	5,808,343
Loss carryforwards	**556,425**	-
Employee future benefits	**698,040**	714,535
Asset retirement obligation	**22,790**	29,530
Regulatory accounts	**(1,781,822)**	(2,029,908)
Reserves, deductible for tax on different basis	**40,000**	9,500
Corporate minimum tax	**15,800**	-
	4,459,975	4,532,000

Presented on the balance sheet as follows:

	2011 $	2010 $
Future income tax assets, long-term	**7,009,840**	6,613,000
Future income tax liabilities, long-term	**2,549,865**	2,081,000

The Corporation has non-capital losses of $2,225,646 (2010- $nil) expiring in 2031.

5. PROPERTY, PLANT AND EQUIPMENT

[a] Details of year-end property, plant and equipment balances are as follows:

	2011		2010	
	Cost	**Accumulated amortization**	Cost	Accumulated amortization
	$	$	$	$
Buildings	**6,213,458**	**1,905,145**	6,170,129	1,732,471
Distribution equipment	**139,088,445**	**70,956,890**	130,541,300	66,639,769
General office equipment	**4,253,740**	**3,802,614**	4,042,815	3,700,717
Land	**133,038**	**-**	133,038	-
Other equipment	**3,205,849**	**2,591,381**	3,143,135	2,504,603
Rolling stock	**6,536,995**	**4,531,615**	6,219,429	4,191,352
Transformation equipment	**8,639,193**	**6,051,061**	8,639,193	5,847,357
Connection costs	**657,816**	**29,236**	654,161	3,655
Generator related equipment	**775,100**	**51,673**	757,776	23,998
Generator	**4,307,657**	**191,425**	4,294,525	6,380
Gas conditioning equipment	**481,803**	**42,827**	476,450	5,353
Infrastructure	**647,840**	**21,595**	645,141	2,699
Radio tower	**115,970**	**2,209**	115,694	276
	175,056,904	**90,177,671**	165,832,786	84,658,630
Property, plant and equipment, net	**84,879,233**		81,174,156	

See note 12 for details of the amortization for the year.

[b] Details of year-end capital contributions balances are as follows:

	2011		2010	
	Capital contributions	**Accumulated amortization**	Capital contributions	Accumulated amortization
	$	$	$	$
Distribution equipment	**15,702,405**	**3,067,428**	12,744,352	2,439,332
Capital contributions, net	**12,634,977**		10,305,020	

See note 12 for details of the amortization for the year.

6. BANK CREDITS

[a] The Corporation has an operating loan available in the amount of $6,395,495 [2010 - $6,395,495] by way of prime rate based loans or bankers' acceptances. $nil [2010 - $nil] was utilized at December 31, 2011. The prime rate based loans bear interest at bank prime. Prime at December 31, 2011 was 3.0% [2010 - 3.0%]. The bankers' acceptances bear a stamping fee at 0.5% per annum.

The operating loan is secured by:

[i] Guarantee of Advance, unlimited, as executed by the Corporation; and

[ii] Subordination Agreement with respect to the $33,490,500 promissory note given to the City of Thunder Bay, with said Subordination Agreement providing for no acceleration rights, as approved by the Bank's legal department.

[b] The Corporation has a letter of credit or stand-by letters of guarantee available in the amount of $9,708,637 [2010 - $9,708,637] of which $9,708,637 [2010 - $9,708,637] was issued at December 31, 2011. This credit will be used to assist in meeting its prudential obligations to the Independent Electricity System Operator ("IESO"). The credit bears interest at bank prime. Prime at December 31, 2011 was 3.0% [2010 - 3.0%]. Amounts payable to the IESO are recorded in current liabilities on the Consolidated Balance Sheet.

7. LONG-TERM DEBT

Long-term debt consists of the following:

	2011 $	2010 $
Bank term loan payable in monthly instalments of $64,400 including interest at a rate of 5.27%, maturing July, 2024.	**7,100,320**	7,484,747
Debenture loan payable in semi-annual instalments of $429,068 including interest at 4.52%, maturing December 15, 2025.	**8,830,871**	9,274,748
	15,931,191	16,759,495
Less amounts included in current liabilities	**872,625**	831,406
Long-term portion	**15,058,566**	15,928,089

Principal repayments required over the next five years and thereafter are as follows:

	$
2012	872,675
2013	915,900
2014	961,338
2015	1,009,045
2016	1,059,137
Thereafter	11,113,096
	15,931,191

As collateral for the above loans and bank indebtedness the Corporation has provided:

A general security agreement representing a first charge on all TBHEDI assets and undertaking, including without limitation, equipment specific to the Smart Meter Program.

A general security agreement representing a first charge on all TBHRPI assets and undertaking, including without limitation, equipment specific to the Project. As well, a second ranking security interest in any subsequent assets acquired.

Subordination of royalties, dividends or any other distribution to the shareholder and/or City of Thunder Bay as applicable, excluding lease payments and cost of fuel to IO's loan payments.

Assignment of the Renewable Energy Standard Offer Program contract.

Guarantee for the amount of the Infrastructure Ontario debenture for the duration of the Stabilization Period.

8. EMPLOYEE FUTURE BENEFITS

The Corporation has a number of unfunded benefit plans providing retirement and post-employment benefits (excluding pension) to most of its employees.

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

	2011 $	2010 $
Accrued benefit obligation at January 1	**2,849,661**	3,011,388
Actuarial gains(losses)	**118,894**	(199,983)
Current service costs	**121,735**	108,777
Interest cost	**131,868**	141,953
Benefits paid in the year or moved to current liability	**(390,446)**	(212,474)
Accrued benefit obligation, end of year	**2,831,712**	2,849,661
Projected accrued benefit obligation at December 31, using a 5.25% [2010 - 5.25%] discount rate	**2,831,712**	2,849,661
Unamortized actuarial (loss)gain	**(39,553)**	8,479
Accrued benefit liability	**2,792,159**	2,858,140

The main actuarial assumptions employed for the valuations are as follows:

[a] General inflation

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2.0%.

[b] Interest (discount) rate

The obligation as at December 31, 2011, of the present value of future liabilities and the expense for the year, were determined using an annual discount rate of 4.25%.

[c] Salary levels

Future general salary and wage levels were assumed to increase at 3.3% per annum.

[d] Medical costs

Medical costs were assumed to increase at a rate of 7.63% in 2011, graded-down by .37% per annum leveling off at 5% in 2018 and thereafter.

9. NOTE PAYABLE TO CITY OF THUNDER BAY

The note is a non-interest bearing note payable to The Corporation of the City of Thunder Bay (sole shareholder of Thunder Bay Hydro Corporation). Principal repayment in the next twelve months is expected to be $nil.

	2011 $	2010 $
Note payable to City of Thunder Bay	**34,931,625**	34,931,625

10. ASSET RETIREMENT OBLIGATION

A reconciliation between the opening and closing ARO liability balances is as follows:

	2011 $	2010 $
Balance, beginning of year	**118,118**	525,119
Adjustment for change in estimate	**-**	(350,443)
ARO liabilities settled in the year	**(32,077)**	(47,495)
Accretion (recovery) expense	**5,119**	(9,063)
Balance, end of year	**91,160**	118,118

At December 31, 2011, the Corporation estimates the undiscounted amount of cash flows required over the next nine years [2010 - ten years] to settle the ARO is $140,702 [2010 - $195,136]. A discount rate of 4.25% [2010 - 5.25%] was used to calculate the carrying value of the ARO liabilities. No assets have been restricted for settlement of the liability.

11. OTHER OPERATING REVENUE

	2011 $	2010 $
Pole line rentals	**464,701**	454,382
Competitive market revenues	**189,443**	200,237
Interest earned	**512,909**	145,338
Utility services	**669,462**	907,674
Reconnection and change of occupancy charges	**221,536**	269,676
Late payment charges	**297,478**	261,868
Sundry earnings	**467,323**	408,448
Generation revenue	**2,445,937**	752,198
	5,268,789	3,399,821

12. AMORTIZATION

	2011 $	2010 $
Amortization of general plant	**5,591,300**	5,150,431
Amortization of capital contributions	**(628,096)**	(509,632)
Amortization of unallocated office and data processing equipment	**46,776**	54,813
	5,009,980	4,695,612
Amortization of other property, plant and equipment included in relevant expense categories in the Consolidated Statement of Operations and Retained Earnings	**692,138**	639,369
	5,702,118	5,334,981
Amortization included in capitalized expenditures	**327,352**	258,662
Amortization of property, plant and equipment	**5,931,145**	5,520,390
Amortization of intangible assets	**71,717**	65,561
Amortization of capital contributions	**(628,096)**	(509,632)
	5,702,118	5,334,981

13. PENSION PLAN

The Corporation's current service pension costs for the year ended December 31, 2011 were $768,721 [2010 - $659,310].

14. STATEMENT OF CASH FLOWS

[a] The net change in non-cash working capital balances related to operations consists of the following:

	2011 $	2010 $
Decrease (increase) in current assets		
Accounts receivable	**(1,426,128)**	(400,675)
Unbilled revenue	**(1,927,499)**	757,267
Payments in lieu of corporate income taxes receivable	**1,500,281**	(217,062)
Stores inventory	**(39,935)**	300,991
Prepaid expenses	**(90,095)**	(7,650)
Due from related party	**52,813**	(52,813)
	(1,930,563)	380,058
Increase (decrease) in current liabilities		
Accounts payable and accrued liabilities	**269,633**	(2,580,398)
Debt retirement charges payable	**(29,391)**	(12,800)
Deferred revenue and contributions	**438,272**	(150,559)
Due to related party	**13,858**	-
Customer deposits	**(797,663)**	671,960
	(105,291)	(2,071,797)
	(2,035,854)	(1,691,739)

[b] During the year, property, plant and equipment were acquired at an aggregate cost of $11,210,064 [2010 - $13,709,236], of which $2,351,956 [2010 - $1,839,888] was funded by cash contributions, $606,097 [2010 - $659,761] was funded by contributions in-kind, $25,000 [2010 - $4,020,387] was funded by a long-term liability, $327,353 [2010 - $258,662] was funded by capitalized amortization and $7,899,658 [2010 - $6,930,538] was funded by cash.

[c] During the year, assets acquired relating to the Smart Meter Initiative amounted to $240,744 [2010 - $422,663] of which $nil [2010 - $412,474] was funded by long-term debt and $240,744 [2010 - $10,189] was funded by cash.

[d] Cash outflows (inflows) during the year for interest and income taxes were as follows:

	2011 $	2010 $
Interest paid (received)	**(329,133)**	783
Income taxes paid	**920,956**	1,080,300

15. RELATED PARTY TRANSACTIONS

The Corporation of the City of Thunder Bay

The Corporation provides certain services to The Corporation of the City of Thunder Bay in the normal course of business at commercial rates.

For the year ended December 31, 2011, pole rental revenue from The Corporation of the City of Thunder Bay in the amount of $316,961 [2010 - $310,263] and other sundry revenues in the amount of $48,312 [2010 - $36,543] were recorded. The Corporation of the City of Thunder Bay also contributed towards capital construction during the year in the amount of $452,797 [2010 - $335,889]. Included in "Accounts receivable" is $213,659 [2010 - $10,625] receivable from The Corporation of the City of Thunder Bay related to these other activities.

For the year ended December 31, 2011, the Corporation billed electricity revenues in the amount of $8,060,667 [2010 - $9,191,485] to The Corporation of the City of Thunder Bay. At December 31, 2011, included in "Accounts receivable" is $614,298 [2010 - $299,644] receivable from The Corporation of the City of Thunder Bay, related to this electricity revenue.

The Corporation purchases certain services from The Corporation of the City of Thunder Bay in the normal course of business at commercial rates. For the year ended December 31, 2011, the Corporation was charged rent of $310,900 [2010 - $302,036], telecommunication costs of $331,352 [2010 - $361,792], water billings of $7,612 [2010 - $8,133], property taxes of $127,753 [2010 - $126,987], lease costs of $2,060 [2010 - $1,760], royalties of $122,297 [2010 - $37,610], and landfill gas charges of $204,808 [2010 - $53,883]. Included in accounts payable is $13,858 related to landfill gas charges.

As at year-end, current amounts owing (to) / from the related party are as follows:

Amounts owed:	**2011** $	**2010** $
Owing to the Corporation of the City of Thunder Bay	**(13,858)**	-
Owing from the Corporation of the City of Thunder Bay	-	52,813
	(13,858)	52,813

All of the above balances are due within 30 days of invoicing.

Included in non-current liabilities is $159,907 (2010 - $37,610) which relate to royalties payable to the Corporation of the City of Thunder Bay. Under the Corporation's long-term debt agreement the Corporation shall not make any royalty payments to related parties when the debt service reserve is less than 10% (see Note 18).

16. FINANCIAL INSTRUMENTS

[a] Fair value

The Corporation's cash, investments, accounts receivable, accounts payable and accrued liabilities, and customer deposits carrying values approximate fair value due to the short maturity of these investments.

The fair market value of the long-term debt approximates its carrying value.

[b] Risk factors

The following is a discussion of risks and related mitigation strategies that have been identified by the Corporation for financial instruments. This is not an exhaustive list of all risks, nor will the mitigation strategies eliminate all risks listed.

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

Credit risk

Financial instruments are exposed to credit risk as a result of the risk of the counter-party defaulting on its obligations. The Corporation monitors and limits its exposure to credit risk on a continuous basis. The Corporation provides reserves for credit risks based on the financial condition and short and long-term exposures to counter-parties.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from the Corporation's customers. The Corporation has approximately 49,800 customers, the majority of which are residential. The Corporation collects security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2011, the Corporation held security deposits in the amount of $1,568,154 [2010 - $1,862,140].

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 Consolidated Statement of Operations and Retained Earnings. Subsequent recoveries of receivables previously provisioned are credited to the Consolidated Statement of Operations and Retained Earnings.

Credit risk associated with accounts receivable is as follows:

	2011 $	2010 $
Total accounts receivable	**9,800,153**	8,395,319
Less: Allowance for doubtful accounts	**(365,729)**	(387,023)
Total accounts receivable, net	**9,434,424**	8,008,296
Of which		
Outstanding for less then 30 days	**8,087,587**	6,734,270
Outstanding for more than 31 days but not more than 180 days	**1,180,498**	1,035,843
Outstanding for more than 181 days	**403,532**	570,835
Amounts unbilled	**128,536**	54,371
Less: Allowance for doubtful accounts	**(365,729)**	(387,023)
Total accounts receivable, net	**9,434,424**	8,008,296

Unbilled revenue represents amounts to which the Corporation has a contractual right to receive cash through future billings but are unbilled at year-end. As at December 31, 2011, total unbilled revenue was $13,517,342 [2010 - $11,589,843]. Unbilled revenue outstanding is considered current.

At December 31, 2011, there were no significant concentrations of credit risk with respect to any class of financial assets or counter-parties. The Corporation's maximum exposure to credit risk is equal to the carrying value of its financial assets.

Interest rate risk

The Corporation is exposed to interest rate risk in holding certain financial instruments. The Corporation's objective is to minimize net interest expense. Under the Corporation's Revolving Credit Facility, the Corporation may obtain short-term borrowings for working capital purposes. These borrowings expose the Corporation to fluctuations in short-term interest rate [borrowings in the form of prime rate loans in Canadian dollars and bankers' acceptances and letters of credit]. The fee payable for bankers' acceptances and letters of credit is based on 0.5% fee per annum plus stamping fee when applicable.

Cash balances that are not required to meet day-to-day obligations of the Corporation are periodically invested in short-term Canadian money market instruments, exposing the Corporation to fluctuations in short-term interest rates. These fluctuations could impact the level of interest income earned by the Corporation.

Liquidity risk

The Corporation monitors and manages 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 is on hand to meet obligations as they fall due while minimizing interest expense. The Corporation has access to credit facilities and monitors cash balances regularly to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due. Liquidity risks associated with financial commitments are as follows:

	December 31, 2011		
	Due within 1 year	Due between 1 year and 5 years	Due after 5 years
	$	$	$
Financial liabilities			
Accounts payable and accrued liabilities	13,191,129	159,907	-
Note payable to City of Thunder Bay	-	-	34,931,625
Long-term debt	872,625	3,945,420	11,113,146

Foreign exchange risk

As at December 31, 2011, the Corporation has limited exposure to the changing values of foreign currencies. While the Corporation purchases goods and services which are payable in U.S. dollars, and purchases U.S. currency to meet the related payables commitments when required, the impact of these transactions is not material to the financial statements.

17. LIABILITY INSURANCE

The Corporation belongs to the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a self-insurance plan that pools the risks of all of its members. Any losses experienced by MEARIE are shared amongst its members. As at December 31, 2011, the Corporation has not been made aware of any assessments for losses.

18. CAPITAL DISCLOSURES

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

- ensure ongoing access to funding in order to maintain and improve the electricity distribution system of the Corporation;
- ensure compliance with covenants related to its credit facilities and the note payable to the City of Thunder Bay ("City Note");
- begin to align its capital structure for regulated activities of the Corporation with the debt to equity structure recommended by the OEB.

As of December 31, 2011, the Corporation's definition of capital includes shareholder's equity and long-term debt and has remained unchanged from December 31, 2010. As of December 31, 2011, shareholder's equity amounts to $51,959,340 [2010 - $49,298,917] and long-term debt amounts to $50,862,816 [2010 - $51,691,120]. The Corporation's long-term capital structure at December 31, 2011 is 49% debt and 51% equity [2010 - 51% debt and 49% equity]. There have been no changes in the Corporation's approach to capital management during the year.

As at December 31, 2011, TBHEDI is subject to debt agreements that contain various covenants. TBHEDI is governed by the Shareholder Declaration which limits future borrowings, liens and provisions of security without prior written consent. The Corporation is also subject to a Subordination Agreement with respect to the $33,490,550 promissory note given to the City of Thunder Bay, with said Subordination Agreement providing for no acceleration rights, as approved by the Bank's legal department.

TBHEDI's revolving credit facility limits the debt to capitalization ratio to a maximum of 60% [2010 - 60%] and a debt service coverage ratio of not less than 1.20:1. As at December 31, 2011, the debt to capitalization ratio was 18% [2010 - 17%] and debt service coverage was 8.1:1 [2010 - 5.3:1]. TBHEDI's long-term debt agreements also include positive and negative covenants such as limitations on funded indebtedness, capital expenditures restrictions on mergers, amalgamations or consolidations, and limitations on providing security or guarantees to any third party. As at December 31, 2011, TBHEDI's was in compliance with the financial covenants included in its long-term debt agreements, City Note and short-term revolving credit facility.

As at December 31, 2011, TBHRPI is subject to a debt agreement that contains various covenants. TBHRPI's long-term debt agreement requires a quick ratio of 1.1:1 or higher and a debt service reserve of 10% of the outstanding loan principles balance, both of which have been waived during the stabilization period. The stabilization period is defined as a period commencing on the effective date of the agreement and ending at such time that the debt service reserve reaches 10% of the committed amount. The agreement also includes positive and negative covenants such as limitations or disbursements to the City of Thunder Bay and restrictions on changes to the current ownership structure. As at December 31, 2011, TBHRPI was in compliance with the financial covenants.

19. COMMITMENTS

[i] The Corporation leases its premises from The Corporation of the City of Thunder Bay under an operating lease for $1,760 annually (adjusted by the Consumer Price Index factor), expiring September, 2030.

In addition, the Corporation purchases the landfill gas at a rate of $0.8856616 per kilowatt hour sold to the OPA monthly and 5% of gross generation revenue ("royalty"). As per the restrictions of the Corporation's debenture, these royalties are restricted from being paid until certain cash flow requirements are achieved.

[ii] The Corporation has entered into an Operations and Maintenance Services Agreement for a five-year term with a third party with options to renew for an additional three, five-year terms.

Charges include a monthly operations charge of $16,980 plus additional maintenance, equipment servicing and stand-by charges based on hourly rates.

20. COMPARATIVE AMOUNTS

Certain comparative amounts presented in the financial statements have been reclassified to conform to current year's presentation.

Thunder Bay Hydro Corporation Consolidated Expenses

Schedule

Year ended December 31	2011	2010
	$	$
OPERATIONS AND MAINTENANCE		
Customer premises/meters and devices	**327,723**	312,909
Distribution	**3,589,778**	3,996,877
Safety and training	**436,851**	434,553
System control/station maintenance	**1,652,587**	1,567,393
Transformer	**711,034**	628,191
Total operations and maintenance expenses	**6,717,973**	6,939,923
UTILITY SERVICES		
Meter service provider	**77,166**	157,204
Utility management services	**335,786**	273,777
Total utility services expenses	**412,952**	430,981
ADMINISTRATION		
Customer-related		
Bad debts	**84,356**	31,790
Billing and collecting	**892,972**	1,094,321
Customer information service	**943,306**	957,903
Information systems	**766,657**	785,868
Meter reading	**52,686**	134,581
Total customer-related administration expenses	**2,739,977**	3,004,463
General		
Corporate	**617,878**	544,078
Directors' expenses	**92,081**	62,398
Finance	**870,153**	784,247
Human resources	**346,891**	345,472
President's office	**364,359**	349,069
Power systems administration	**260,734**	297,617
Renewable generation activities	**97,995**	130,735
Total general administration expenses	**2,650,091**	2,513,616
Total administration expenses	**5,390,068**	5,518,079

APPENDIX 1-F
Revenue Requirement Work Form ("RRWF")

Revenue Requirement Workform

Version 3.00

Utility Name	Thunder Bay Hydro Electricity Distribution Inc.
Service Territory	*Thunder Bay*
Assigned EB Number	EB-2012-0167
Name and Title	Jenni Pajala, Supervisor of Regulatory Affairs
Phone Number	807-343-1016
Email Address	japajala@tbhydro.on.ca

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While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the

1. Info

2. Table of Contents

3. Data_Input_Sheet

4. Rate_Base

5. Utility Income

6. Taxes_PILs

7. Cost_of_Capital

8. Rev_Def_Suff

9. Rev_Reqt

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)		(6)		Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$174,982,258			$ 174,982,258		$174,982,258	
	Accumulated Depreciation (average)	($95,076,084)	(5)		($95,076,084)		($95,076,084)	
	Allowance for Working Capital:							
	Controllable Expenses	$14,418,846			$ 14,418,846		$14,418,846	
	Cost of Power	$97,020,439			$ 97,020,439		$97,020,439	
	Working Capital Rate (%)	13.00%	(9)		13.00%	(9)	13.00%	(9)
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$18,341,720						
	Distribution Revenue at Proposed Rates	$19,901,055						
	Other Revenue:							
	Specific Service Charges	$267,807						
	Late Payment Charges	$297,000						
	Other Distribution Revenue	$856,920						
	Other Income and Deductions	$330,008						
	Total Revenue Offsets	$1,751,736	(7)					
	Operating Expenses:							
	OM+A Expenses	$14,682,415			$ 14,682,415		$14,682,415	
	Depreciation/Amortization	$3,247,244	(10)		$ 3,247,244		$3,247,244	
	Property taxes							
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($2,831,251)	(3)					
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$ -						
	Income taxes (grossed up)	$ -						
	Federal tax (%)	0.00%	###					
	Provincial tax (%)	0.00%	###					
	Income Tax Credits	$ -						
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%						
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%						
	Prefered Shares Capitalization Ratio (%)							
		100.0%						
	Cost of Capital							
	Long-term debt Cost Rate (%)	1.89%						
	Short-term debt Cost Rate (%)	2.08%						
	Common Equity Cost Rate (%)	7.00%						
	Prefered Shares Cost Rate (%)							
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS ($)	$ -	(11)			(11)		(11)

Notes:

General	Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.
(1)	All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2)	Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I
(3)	Net of addbacks and deductions to arrive at taxable income.
(4)	Average of Gross Fixed Assets at beginning and end of the Test Year
(5)	Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
(6)	Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.
(7)	Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement
(8)	4.0% unless an Applicant has proposed or been approved for another amount.
(9)	Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.
(10)	Depreciation Expense should include the adjustment resulting from the amortization of the deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.
(11)	Adjustment should include the adjustment to the return on rate base associated with deferred PP&E balance as shown on Appendix 2-EA or Appendix 2-EB of the Chapter 2 Appendices to the Filing Requirements.
(12) & (13)	Inputted as 0% in order to force income tax payable as $0 for 2013 since taxable income is negative.

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application							Per Board Decision
1	Gross Fixed Assets (average)	(3)	$174,982,258		$ -		$174,982,258		$ -	$174,982,258
2	Accumulated Depreciation (average)	(3)	($95,076,084)		$ -		($95,076,084)		$ -	($95,076,084)
3	Net Fixed Assets (average)	(3)	$79,906,174		$ -		$79,906,174		$ -	$79,906,174
4	Allowance for Working Capital	(1)	$14,487,107		$ -		$14,487,107		$ -	$14,487,107
5	**Total Rate Base**		$94,393,281		$ -		$94,393,281		$ -	$94,393,281

Allowance for Working Capital - Derivation

(1)

6	Controllable Expenses		$14,418,846		$ -		$14,418,846		$ -	$14,418,846
7	Cost of Power		$97,020,439		$ -		$97,020,439		$ -	$97,020,439
8	Working Capital Base		$111,439,285		$ -		$111,439,285		$ -	$111,439,285
9	Working Capital Rate %	(2)	13.00%		0.00%		13.00%		0.00%	13.00%
10	Working Capital Allowance		$14,487,107		$ -		$14,487,107		$ -	$14,487,107

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. Default rate for 2013 cost of service applications is 13%.

(3) Average of opening and closing balances for the year.

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$19,901,055	($19,901,055)	$ -	$ -	$ -
2	Other Revenue	(1)	$1,751,736	($1,751,736)	$ -	$ -	$ -
3	Total Operating Revenues		$21,652,790	($21,652,790)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$14,682,415	$ -	$14,682,415	$ -	$14,682,415
5	Depreciation/Amortization		$3,247,244	$ -	$3,247,244	$ -	$3,247,244
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$17,929,659	$ -	$17,929,659	$ -	$17,929,659
10	Deemed Interest Expense		$1,080,120	($1,080,120)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$19,009,779	($1,080,120)	$17,929,659	$ -	$17,929,659
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		$ -	$ -	$ -	$ -	$ -
13	**Utility income before income taxes**		$2,643,012	($20,572,670)	($17,929,659)	$ -	($17,929,659)
14	Income taxes (grossed-up)		$ -	$ -	$ -	$ -	$ -
15	**Utility net income**		$2,643,012	($20,572,670)	($17,929,659)	$ -	($17,929,659)

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$267,807		$ -		$ -
	Late Payment Charges	$297,000		$ -		$ -
	Other Distribution Revenue	$856,920		$ -		$ -
	Other Income and Deductions	$330,008		$ -		$ -
	Total Revenue Offsets	$1,751,736	$ -	$ -	$ -	$ -

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$2,643,012	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($2,831,251)	$ -	($2,831,251)
3	Taxable income	($188,239)	$ -	($2,831,251)
	Calculation of Utility income Taxes			
4	Income taxes	$ -	$ -	$ -
6	Total taxes	$ -	$ -	$ -
7	Gross-up of Income Taxes	$ -	$ -	$ -
8	Grossed-up Income Taxes	$ -	$ -	$ -
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$ -	$ -	$ -
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	0.00%	0.00%	0.00%
12	Provincial tax (%)	0.00%	0.00%	0.00%
13	Total tax rate (%)	0.00%	0.00%	0.00%

Notes

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$52,860,237	1.89%	$1,001,585
2	Short-term Debt	4.00%	$3,775,731	2.08%	$78,535
3	**Total Debt**	60.00%	$56,635,968	1.91%	$1,080,120
	Equity				
4	Common Equity	40.00%	$37,757,312	7.00%	$2,643,012
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$37,757,312	7.00%	$2,643,012
7	**Total**	100.00%	$94,393,281	3.94%	$3,723,132
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$94,393,281	0.00%	$ -
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	1.89%	$ -
9	Short-term Debt	0.00%	$ -	2.08%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	7.00%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$94,393,281	0.00%	$ -

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates			Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
				At Current Approved Rates	At Proposed Rates		
1	Revenue Deficiency from Below		$1,559,334		($412,062)		$17,929,659
2	Distribution Revenue	$18,341,720	$18,341,720	$18,341,720	$20,313,117	$ -	($17,929,659)
3	Other Operating Revenue Offsets - net	$1,751,736	$1,751,736	$ -	$ -	$ -	$ -
4	**Total Revenue**	$20,093,456	$21,652,790	$18,341,720	$19,901,055	$ -	$ -
5	Operating Expenses	$17,929,659	$17,929,659	$17,929,659	$17,929,659	$17,929,659	$17,929,659
6	Deemed Interest Expense	$1,080,120	$1,080,120	$ -	$ -	$ -	$ -
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ - (2)	$ -	$ - (2)	$ -	$ - (2)	$ -
8	**Total Cost and Expenses**	$19,009,779	$19,009,779	$17,929,659	$17,929,659	$17,929,659	$17,929,659
9	**Utility Income Before Income Taxes**	$1,083,677	$2,643,012	$412,062	$1,971,396	($17,929,659)	($17,929,659)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,831,251)	($2,831,251)	($2,831,251)	($2,831,251)	$ -	$ -
11	**Taxable Income**	($1,747,574)	($188,240)	($2,419,189)	($859,855)	($17,929,659)	($17,929,659)
12	Income Tax Rate	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	**Income Tax on Taxable Income**	$ -	$ -	$ -	$ -	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$1,083,677	$2,643,012	$412,062	($17,929,659)	($17,929,659)	($17,929,659)
16	**Utility Rate Base**	$94,393,281	$94,393,281	$94,393,281	$94,393,281	$94,393,281	$94,393,281
17	Deemed Equity Portion of Rate Base	$37,757,312	$37,757,312	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	2.87%	7.00%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	7.00%	7.00%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-4.13%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	2.29%	3.94%	0.44%	0.00%	-18.99%	0.00%
22	Requested Rate of Return on Rate Base	3.94%	3.94%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-1.65%	0.00%	0.44%	0.00%	-18.99%	0.00%
24	Target Return on Equity	$2,643,012	$2,643,012	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$1,559,334	($0)	($412,062)	$ -	$17,929,659	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,559,334 (1)		($412,062) (1)		$17,929,659 (1)	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

(2) Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$14,682,415		$14,682,415		$14,682,415	
2	Amortization/Depreciation	$3,247,244		$3,247,244		$3,247,244	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$ -		$ -		$ -	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$1,080,120		$ -		$ -	
	Return on Deemed Equity	$2,643,012		$ -		$ -	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ -		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$21,652,791		$17,929,659		$17,929,659	
9	Revenue Offsets	$1,751,736		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$19,901,055		$17,929,659		$17,929,659	
11	Distribution revenue	$19,901,055		$ -		$ -	
12	Other revenue	$1,751,736		$ -		$ -	
13	**Total revenue**	$21,652,790		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($17,929,659)	(1)	($17,929,659)	(1)

Notes

(1) Line 11 - Line 8

APPENDIX 1-G
2011 ANNUAL REPORT

THUNDER BAY HYDRO

2011 Annual Report

About Thunder Bay Hydro

THUNDER BAY HYDRO CORPORATION
is a group of companies serving Thunder Bay and area with electricity distribution, generation and utility services.

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
is responsible for the electricity distribution system and delivering electricity to the homes and businesses within the city limits of Thunder Bay and Fort William First Nation. We are the local front line customer service face of the province's electrical industry providing for the reading of
customer meters, billing and energy conservation advice and programs. We build and maintain the local electricity distribution system and respond to outages and emergencies around the clock.

THUNDER BAY HYDRO RENEWABLE POWER INCORPORATED
is a subsidiary whose strategy is to develop renewable energy generation projects in the Thunder Bay area. The company owns and operates the Mapleward Renewable Generating Station.

THUNDER BAY HYDRO UTILITY SERVICES INC.
provides back office systems and support, IT hosted applications and program management that includes conservation programs to other electric utility companies in the district.

THUNDER BAY HYDRO

Thunder Bay Hydro RENEWABLE POWER

Message from the President & The Chair of the Board of Directors

During 2011, the Board of Directors increased the size of the Board bringing the number of directors up from five to seven. This change allowed us to welcome a newly expanded group of board members and position ourselves to better serve the governance needs of the corporation.

We have an active Audit Committee who ensures that the board undertakes its fiduciary responsibilities. In 2011, we established a separate Governance Committee that will continue the work of improving our adherence to the principles of good corporate governance. This has allowed much of our focus to be placed on seeking avenues to grow the value of the corporation to the shareholder.

Our commitment to annually update a formal three-year strategy is a vital part of our work.

The environment in which we operate has a significant impact on how our business strategy is developed and pursued. That environment has proven to provide both challenges and opportunities for the corporation.

While responding to the many regulatory changes, we have been able to improve our efficiency and leverage our expertise to provide services to regional utilities.

We've taken advantage of the Province's authorization to participate in renewable generation projects and realize a beneficial return for our efforts. Our Mapleward Renewable Generating Station has been running for a full year and is producing above our expectations. Our photovoltaic solar projects are well on their way to come into production in 2012.

From a demographic perspective, the employee base that we work with is undergoing tremendous change. Aging baby boomers have been retiring and creating a gap in skills and experience at senior levels that are difficult to replace. The skills retention and succession planning done by our Human Resources has been vital to our success in filling these gaps.

The new Time-of-Use method of electricity pricing was introduced this past year and its impact may have been somewhat cushioned by a mild winter. Our role in

Continued

the coming year will be to continue to educate our customers to help them adapt to the changed price structure.

The core of our business is to distribute a reliable supply of electricity to our customers. Like many other utilities, aging infrastructure is an issue. Several years ago, we committed to increase our capital budget annually until we are able to achieve funding to ensure a responsible level of ongoing upkeep of this vital equipment. We are on track to continue that course of action.

Thunder Bay Hydro provides an essential service that affects both our local economy as well as the comfort we enjoy in our homes. We believe that our performance for 2011 continues to illustrate our commitment to "Safety, Reliability and Shareholder Value". The diligent work of both outgoing and incoming board members has been vital to this success.

Sincerely,

Ralph Falcioni,
Chair

Robert Mace, MBA
President & CEO

Corporate Goals

Supporting Our Corporate Goals

Our ability to achieve our Corporate Goals depends on strategic initiatives that focus on creating a work culture of health and safety, effectively managing our assets, growing our value by using our expertise in utility services and renewables, being efficient in the use of our scarce resources and focusing in on service to our community of customers.

In turn, we rely on having access to appropriate resources in order to carry out these initiatives: the ability to attract, develop and retain skilled staff; support for ongoing operations and the capital investment to maintain a service over the long term; expertise to cope with an increasingly complex industry; and access to timely data, best practices and intelligence.

CHALLENGES

Human resources continue to be challenged because with the retirement of baby boomers, competition for skilled workers has increased and many of the roles being vacated are those of senior personnel whose years of experience are difficult to replace.

Our ability to grow distribution revenue has been pressured by a static local market size and moderate weather conditions that reduce the need for extensive heating and cooling.

Government policies and regulatory demands shift with the political landscape. Finding expertise to deal with these changes often means building external partnerships.

OPPORTUNITIES

The changing electricity industry environment has opened doors to actively invest in local renewable generation projects.

The increasing complexity of regulatory demands and information needs has made our expertise in the industry valuable to other small district local distribution companies.

2011 Highlights

Tackling an Aging Infrastructure

Historical limits in spending for equipment replacement created an aging infrastructure that was finally addressed in the 2008 budget. Since then, we have created an accelerated plan to catch up on deficits in the age of our distribution system.

The average age of our infrastructure is approximately 32 years. With 20,000 poles, we have to replace about 400 poles each year and maintain the average age of our poles at about 25 years in order to sustain a robust, reliable distribution system to serve our community.

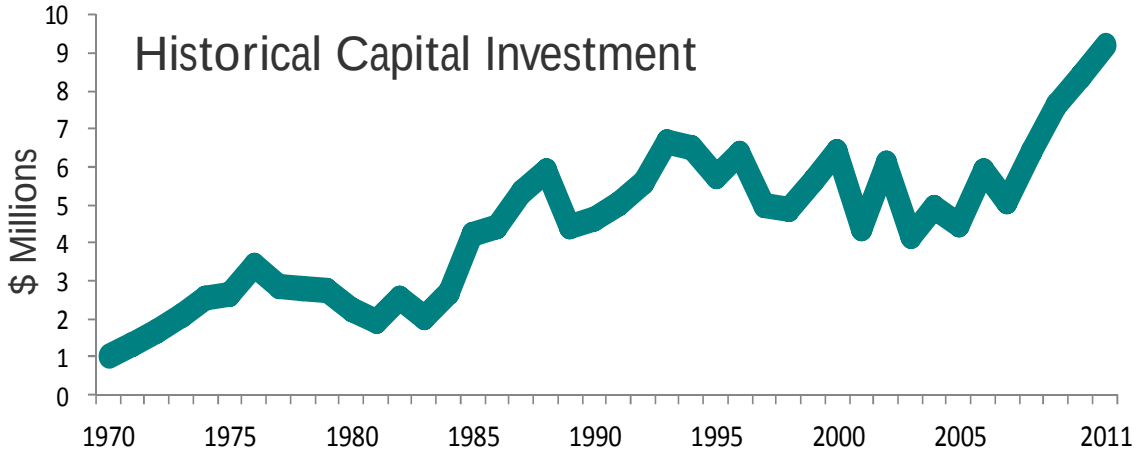
495 Number of poles set in 2011

In 2011, we were able to replace 495 poles and upgrade related equipment for these lines. This number is in addition to poles that may have been replaced in the normal course of operations. In total, we spent over $9 million dollars investing in our distribution infrastructure during the year.

$9 million Value of capital investment in infrastructure

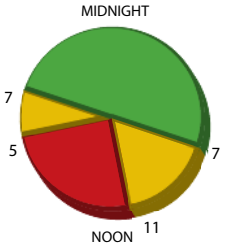
Areas of major rebuild focused on overhead lines in the Westfort area and underground lines within the College Park area.

As we replace lines within the city, we are upgrading the capacity of our lines from 4 kV to 25kV. This move will allow us to decommission sub-stations that are at their end of life and reduce system losses to create a more efficient distribution system.



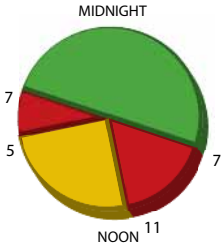
Implementing Time-of-Use Electricity Pricing

Summer-Weekdays



Weekends & Holidays

Winter-Weekdays



The first consumer bills based on the Province's new pricing system were rolled out in late 2011.

The project to implement Time-of-Use pricing locally was a multi-year, multi-million dollar undertaking.

Planning began in 2006. Installation of Smart Meters, which are capable of measuring and reporting consumption by the hour, began in 2008.

Integration and testing consumed most of 2010 and 2011.

Thunder Bay Hydro now delivers daily energy consumption to the provincial repository.

Consumer education played a big role in the transition. Starting with Phantom Load seminars in 2008, our staff began educating customers about how they use electricity and where they can shift their use. We continued our ongoing seminars during 2011 with a focus on the tools and programs that will help consumers adapt to the new pricing.

Household deliveries included the Smart Meter Book, a removable decal with Time of Use periods illustrated and a newsletter dedicated to the new way that electricity is priced.

Extensive advertising went out in the form of printed ads, submitted articles, billboards and transit shelters.

Consumer acceptance was measured by the number of calls received by our Customer Services. In the month following complete transition to the system, only nineteen of 3,400 customer calls were about Time-of-Use.

Implementation of the new pricing system has created a consumer demand to know their consumption patterns. Providing this data is currently under consideration.

It has taken concerted effort from staff from across the organization to successfully complete the conversion to this new mode of pricing.

Safety

The company commitment to safety resonated throughout the year. In a recent employee survey, 93% of staff agreed that "Safety is the #1 priority at Thunder Bay Hydro".

A new symbol of that commitment was launched in January with the "Committed to Safety" logo. The purpose of the logo is to illustrate the interdependent work that is done by the company, the union and the overall employee group to make their workplace safe.

As of December 31, 2011 we had achieved 619 days without a lost time incident.

Public Safety Initiatives

Our annual spring school program "Hi Line Hazard & Energy Conservation" was very successful and the presentation was delivered to over 1360 elementary students in Grades Three to Six. The students were from 42 classes in 15 schools. We were also able to provide take home electrical safety bags for 2,500 students as a Silver Sponsor to the St. John's Ambulance school safety program.

Human Resources

Zero was a good number in the Human Resources field during 2011. We closed the year with zero outstanding grievances, zero arbitrations and zero outstanding/ unfilled vacancies.

We held job competitions for 14 positions during the year mainly due to a growing number of retirements from our employees and as a result of promotions within the organization.

Over $55,000 was secured to fund student and intern placements during the year.

Policies, communication and training to implement Bill 168 regarding violence and harassment in the workplace were all completed. Requirements of the Ontario Accessibility Act were carried out.

Several new wellness initiatives were started and the Employee Rewards and Recognition program underwent an update.

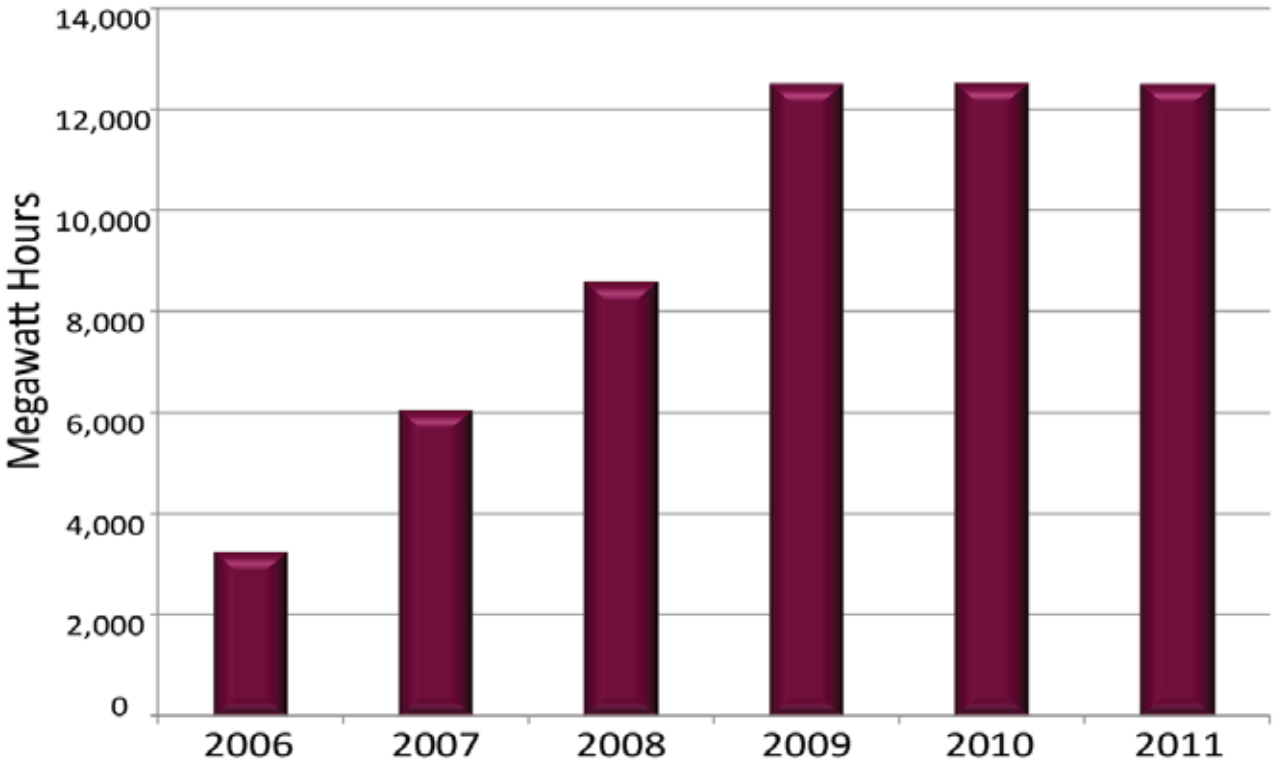
Conservation & Energy Services

The Conservation and Energy Services Department has been working under the funding of the Ontario Power Authority to implement programs to reduce the demand for electricity within our system. Through the years, their work has impacted both the overall energy savings as well as peak demand. Targets for these savings have been set under the Green Energy Act and constitute a regulatory requirement for our operation.

The year was largely a preparation year for Conservation and Demand Management programs. As the OPA released programs for use, Thunder Bay Hydro worked diligently in bringing them to market. However, due to late releases, a number of programs did not get to market until late in 2011 and many were not ready for release by year end.

One hundred and forty-seven local companies have participated with Thunder Bay Hydro in the province's business retrofit programs since 2007. As of the end of December 2011, the Thunder Bay business participants have produced cumulative electricity savings of 798 kW of demand and benefitted from $400,000 worth of locally paid out provincial incentives.

Last year, Energy Services staff delivered fourteen seminars to 550 attendees from our residential customer base focusing on the conservation opportunities with Time-of-Use pricing.



Net Energy Savings from Local Conservation Programs

Renewable Power

The Mapleward Renewable Generating Station had its first full year of operation in 2011. Despite significant downtime caused by a Hydro One upgrade at the Fort William Transformer Station, total 2011 generation exceeded the budget by 2.6% providing over twenty million kWhs to the grid.

A project to install solar photovoltaic generation has begun on six city-owned buildings:

- Transit Building
- Port Arthur Arena
- Mountdale Garage
- Victoriaville Parkade
- TBayTel Work Centre
- EMS Headquarters

As of the end of 2011, Feed-In Tariff contracts have been received for all sites. Five Connection Impact Assessments have been approved. Four "Notice to Proceed" status updates have been issued.

Completed construction is anticipated to take place in 2012.

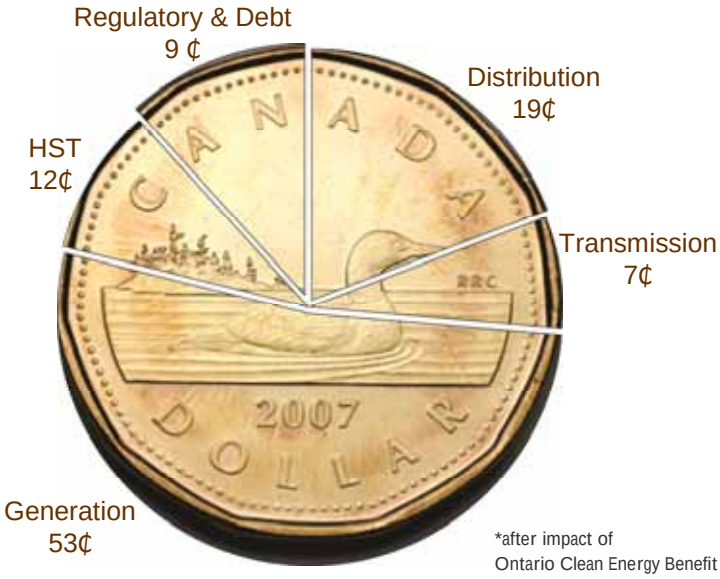
Financial Picture

CONSOLIDATED FINANCIAL HIGHLIGHTS

Total Revenue	$22,770,753
Total Expenses	$19,228,830
Earnings Before Taxes	$3,541,923
Payment in lieu of Corporate Taxes	$881,500
Earnings for Year	$2,660,423

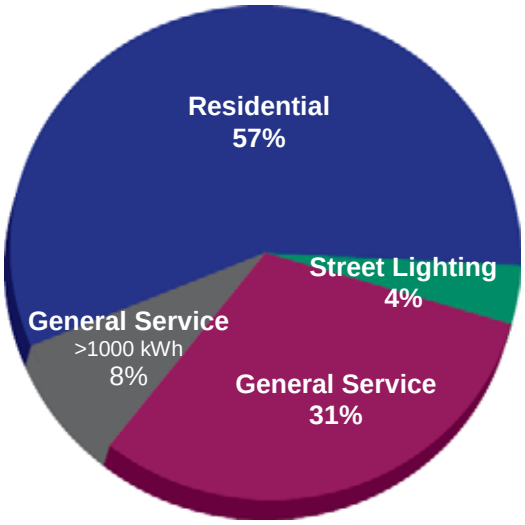
Who Are Our Customers?

Where Each Dollar on an Electricity Bill is Distributed*



*after impact of Ontario Clean Energy Benefit

Where our Distribution Revenue Comes From



2011 Board of Directors

Back L-R:

Frank Pullia [2]
Darrell Matson, City Liaison
Art Leitch [2]
Hartley Multamaki [1, 2, 3, 4]

Front L-R:

David O'Brien [2]
Mark Bentz [1, 2, 3, 4]
Ralph Falcioni, Chair [1, 2, 3, 4]
Gary Armstrong [2]

Legend:

1. Thunder Bay Hydro Corporation
2. Thunder Bay Hydro Electricity Distribution Inc.
3. Thunder Bay Hydro Renewable Power Incorporated
4. Thunder Bay Hydro Utility Services Incorporated

Executive Team

Robert Mace

President & CEO

Tim Wilson

Vice President,
Customer Service & Conservation

Andrew Covello

Vice President,
Human Resources & Safety

Cindy Speziale

Vice President,
Finance

Don Zimak

Vice President,
Power Systems

THUNDER BAY HYDRO

APRIL 2012

Exhibit	Tab	Schedule	Appendix	Contents
2 – Rate Base				
	1			
		1		Overview
		2		Variance Analysis of Rate Base
	2			Gross Assets – Property, Plant & Equipment & Accumulated Amortization
		1		Continuity Statements
		2		Gross Asset Table
		3		Variance Analysis on Gross Assets
		4		Accumulated Depreciation Table
		5		Variance Analysis on Accumulated Depreciation
	3	1		Capital Budget
		2		Capital Projects by Year and USoA
		3		Asset Management Plan Summary
		4		Capitalization Policy
		5		Service Quality & Reliability Performance
	4			Allowance for Working Capital
		1	1	Overview and Calculation by Account
	5			Summary of Changes as a Result of Modifying Capitalization and Depreciation Policy "Modified" CGAAP (MCGAAP)
			1	Impact on Fixed Assets
			2	Impact on Capitalization of Burdens
			3	Other Impacts on Capital
			4	Impact on Rate Base
	6			Green Energy Plan – Capital Expenditures
			2-A	Asset Management Plan
			2-B	Green Energy Act Plan
			2-C	OPA Letter of Communication
			2-D	Service Quality & Reliability Performance (2009-2011)

OVERVIEW

Rate Base Overview

The rate base used for the purpose of calculating the revenue requirement used in this Application is the average of the balances at the beginning and the end of the 2013 Test Year, plus a working capital allowance, which is 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 conveyance of electricity for distribution purposes. The rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

Thunder Bay Hydro has provided its rate base calculations for the years 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year in Table 2-1.1 below. Thunder Bay Hydro has calculated its 2013 rate base using both CGAAP and MCGAAP. As noted throughout this application, Thunder Bay Hydro has modified its capitalization and depreciation policies to align with the APH Guidelines regarding MIFRS. Table 2-1.1 shows what will be used to determine the proposed revenue requirement.

Table 2-1.1 - Rate Base Calculations

	2009 Board approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge (CGAAP)	2013 Test (CGAAP)	2013 Test (MCGAAP)
Fixed Assets Opening Balance	60,721,376	61,016,106	61,199,061	62,895,512	64,506,734	75,733,639	75,651,562
Fixed Assets Closing Balance	63,383,477	61,199,061	62,895,512	64,506,734	75,651,562	82,880,471	84,160,785
Average Fixed Asset Balance	62,052,427	61,107,583	62,047,286	63,701,123	70,079,148	79,307,055	79,906,174
Working Capital Allowance	13,480,846	12,893,612	13,579,694	14,628,533	16,546,714	14,322,732	14,487,107
Rate Base	75,533,273	74,001,196	75,626,981	78,329,656	86,625,862	93,629,788	94,393,281

Thunder Bay Hydro's Distribution System

Thunder Bay Hydro owns and operates the electricity distribution system in its licensed service area in the City of Thunder Bay and the Fort William First Nation Reserve serving approximately 49,800 Residential, General Service, and unmetered scattered load customers.

As of September 2012, Thunder Bay Hydro is supplied through the Hydro One transmission system at voltages of 115 kV and 230 kV. Electricity is then distributed through an urban/rural service area of 259/122 square kilometres over 234 kilometres of underground cable and 935 kilometres of overhead cable and 19,707 poles. Thunder Bay Hydro owns 17 distribution sub-stations stepping voltage down to 4 kV and 12 kV. Voltage is further stepped down in order to supply individual customers through approximately 7,100 transformers.

Thunder Bay Hydro monitors its distribution system through the control centre and operates the Supervisory Control and Data Acquisition ("SCADA") systems twenty-four hours a day, seven days a week.

In managing its distribution system assets, Thunder Bay Hydro's main objective is to optimize performance of assets at a reasonable cost with due regard for system reliability, public and worker safety and customer service expectations. This Application incorporates Thunder Bay Hydro's 2013 Capital and Expense Budgets in determining the revenue requirement to bring these plans to fruition. Further information will be provided later in this Application.

In addition to the capital needs of the network, Thunder Bay Hydro provides and plans for system maintenance of the network on a priority basis. Preparation and consideration are undertaken before the final recommended budget amounts are established. Further information on Thunder Bay Hydro's Capital and Operation, Maintenance & Administration amounts will follow later in this Application.

Capital Asset Categories

Thunder Bay Hydro's assets fall into two broad categories – The first is ***distribution plant***, which includes assets such as transformation, substation buildings, poles, conductor, overhead and underground electricity distribution infrastructure, transformers, meters and substation

equipment. The second is ***general plant*** which includes assets such as: office building and the service centre; office furniture; transportation equipment; communications technology; computer equipment and software; general equipment; and tools. A more detailed list of distribution and general plant categories can be found in Table 2-2.7 (Gross Assets) in Exhibit 2, Tab 2, Schedule 2.

Distribution Plant Capital Projects

Thunder Bay Hydro's Distribution capital budget items include:

PART A – CUSTOMER/REGULATORY DRIVEN CAPITAL COSTS

(1) Regulatory/Legal

This project reflects all regulatory or legal compliance capital requirements to ensure the organization remains compliant with its obligations. This includes Polychlorinated Biphenyls (PCB) legislation requiring removal of PCBs.

(2) Customer Driven Expansions

This project contains all resource requirements including any customer contributions for main distribution system upgrades or expansions to facilitate customer upgrades or connect new customers. Expansions driven by lot severances are included in this project.

(3) Services – Residential

This is the total cost including any customer contributions received for all new connection assets required to connect a new service to residence or small general services (200 Amp Max) from the supply line abutting the customers' premises.

(4) Services – General

This project covers the total requirements to meet new commercial customer connection requirements from the supply line abutting the customers' premises. This amount includes any customer contributions received. This includes only connection facilities and excludes any system expansion required to reach the customers' property.

(5) Subdivisions

This project captures any construction activity as well as Thunder Bay Hydro's contributions for new subdivisions towards expansion and connection assets. The majority of subdivision work is done by a developer; however, according to OEB requirements an economic evaluation must be performed and depending on the additional load Thunder Bay Hydro must contribute accordingly. The developer is allowed to recover these costs when this equipment is turned over to the utility.

(6) Relocations

This project captures the total costs associated with requests from customers, The Corporation of the City of Thunder Bay or the Ministry of Transportation (MTO) to relocate the utility's plant. While this work may be recoverable, the Highway Traffic Act requires that only the existing book value of the equipment along with 50% of the labour be recoverable by Thunder Bay Hydro for MTO requests.

(7) Small Unplanned Replacements

These are small line upgrades that are required by either customer upgrades where the work is scheduled in the next five years as a large rebuild and it is more efficient to rebuild a small component of the larger project now or where large projects are scheduled as Part B Capital in the coming years and a small portion of that project's assets are in such poor condition that it is determined that this portion must be rebuilt immediately to ensure the assets perform reliably and safety is not compromised by waiting.

(8) Lines Safety Reports

This account reflects all the capital requirements to address any Lines safety issues discovered that must be dealt with immediately. This is typically made up of single pole replacements.

(9) Transformers

This project reflects all of the transformers and switchgear required for Operating & Maintenance activities for the year.

(10) Meters

This account captures all the costs of meter replacements which are dictated by Measurement Canada, Legislated Green Energy programs, new general service customer connections, and new residential customer connections and in service failed meters.

(11) Operations Safety Reports

All substations are thoroughly inspected on an annual basis and where an immediate danger to the general public or Thunder Bay Hydro employees is determined to exist, a safety concern report is issued and a plan of action drafted to address the issue. This account reflects all the capital requirements to address any Stations or Operations Centre safety issues discovered.

(12) Generator Driven Expansion/ Renewable Generation Enable Improvements

This project will cover expansion or reinforcement of Thunder Bay Hydro's distribution system to accommodate the connection of renewable energy generation facilities. This project will account for improvements to existing, as well as additional equipment required for the distribution system to accommodate two-way flows of power that will occur with significant generation located on the distribution system.

PART B – CAPTIAL COSTS FOR REBUILDING THE SYSTEM

(13) Line Replacements

This is a subset of all planned projects whose primary driver within the 20-year capital plan is to replace overhead plant that is at the end of its useful life.

(14) Line Voltage Conversions

This is a subset of all planned projects whose primary driver within the 20-year capital plan is to replace the old 4kV system with a functionally equivalent 25kV system, thereby facilitating the removal of Thunder Bay Hydro's nearing end of life 4/25 kV substations.

(15) System Improvements

This is a subset of all planned projects whose primary driver within the 20-year capital plan is to enhance the distribution system such that the benefits warrant the upgrade either via improved operational, maintenance, risk reduction, or reliability improvements.

(16) Underground (U/G) Installations/Replacements

This is a subset of all planned projects whose primary driver within the 20-year capital plan is either to replace underground plant that is at the end of its useful life or the installation of required U/G plant to serve Thunder Bay Hydro's customers.

(17) Unplanned Capital

This project captures the costs for pulling old poles or removing equipment for capital projects that have been closed.

(18) Stations

This is a subset of all planned projects whose primary driver within the 20-year capital plan is to sustain or enhance any one of the 17 substation's assets including relaying, SCADA and communications equipment located at each substation.

(19) Wholesale Metering

This is a subset of all planned projects required to maintain Thunder Bay Hydro's wholesale metering at the Hydro One Supply Stations in accordance with Measurement Canada's and the Independent Electricity System Operator's (IESO) requirements.

General Plant Capital Projects

Thunder Bay Hydro's general plant capital projects for 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and the 2013 Test Year are discussed in further detail in Exhibit 2, Tab 3, Schedule 2.

Gross Assets – Property, Plant and Equipment and Accumulated Amortization

The 2012 Bridge and 2013 Test Years' gross asset balances reflect the capital expenditure programs forecast for both years. An analysis of 2009 to 2013 capital programs has been completed and is described in detail in Thunder Bay Hydro's written evidence at Exhibit 2, Tab 3, Schedule 2.

Budget Process

Thunder Bay Hydro's budget is primarily guided by its Asset Management Plan, which sets out processes for determining the necessary distribution system investments to ensure safe, reliable delivery of electricity to its customers. See Appendix 2-A for the Asset Management Plan.

The budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, it typically does not change but provides a plan against which actual results are evaluated.

Responsibilities

- It is the responsibility of the Finance department to co-ordinate the development of the operating budget, capital budget and forecast processes.
- Each department is responsible for preparing its respective operating budget, capital budget, and forecasts.
- The Executive Management Team reviews the organizational budget as a group to ensure that each Vice President has a good understanding of the plans of other members of the Team for the upcoming year.
- The President is responsible for presenting and recommending the budget to the Board of Directors for approval.
- It is the responsibility of the Board of Directors, on behalf of the Shareholder, to approve the budget.

The budget is an important planning tool for Thunder Bay Hydro. It puts capital and operational plans into a common financial plan. 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.

The departmental Budget Plans represent the output of detailed work plans based on required activities for the year. Thunder Bay Hydro notes that these Budget Plans address both capital and operating requirements.

VARIANCE ANALYSIS OF RATE BASE

Table 2-1.2 below sets out Thunder Bay Hydro's rate base and working capital calculations for 2009 Board Approved and Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and the 2013 Test Year and the variances. As discussed in Exhibit 1, Tab 4, Schedule 1 the materiality threshold calculated is $85,000. Given the nature of the Rate Base and Working Capital Calculations, as can be expected, all of the variances exceed the materiality threshold. As such, the summary paragraphs below Table 2-1.2 address the explanations for the following rate base variances.

Table 2-1.2 – Thunder Bay Hydro's Rate Base and Working Capital Calculations

Description	2009 Board Approved	2009 Actual	Variance from 2009 OEB Approved	2010 Actual	Variance from 2009 Actual	2011 Actual	Variance from 2010 Actual	2012 Bridge	Variance from 2011 Actual	2013 Test (CGAAP)	Variance from 2012 Bridge	2013 Test (MCGAAP)	Variance from 2013 Test (CGAAP)
Gross Fixed Assets	146,027,521	140,898,733	(5,128,788)	147,645,599	6,746,867	155,027,528	7,381,928	171,366,052	16,338,525	184,224,014	12,857,962	181,875,185	(2,348,829)
Accumulated Depreciation	81,690,469	77,957,748	(3,732,721)	82,917,995	4,960,246	87,478,705	4,560,710	94,363,618	6,884,913	100,265,561	5,901,943	96,620,781	(3,644,780)
Net Book Value	64,337,051	62,940,985	(1,396,067)	64,727,605	1,786,620	67,548,823	2,821,218	77,002,434	9,453,611	83,958,453	6,956,019	85,254,405	1,295,952
Average Net Book Value	62,052,427	61,107,583	(944,844)	62,047,286	939,703	63,701,123	1,653,837	70,079,148	6,378,025	79,307,055	9,227,907	79,906,174	599,118
Working Capital	89,872,307	85,957,416	(3,914,891)	90,531,296	4,573,880	97,523,555	6,992,259	110,311,424	12,787,869	110,174,865	(136,559)	111,439,285	1,264,420
Working Capital Allowance	13,480,846	12,893,612	(587,234)	13,579,694	686,082	14,628,533	1,048,839	16,546,714	1,918,180	14,322,732	(2,223,981)	14,487,107	164,375
Rate Base	75,533,273	74,001,196	(1,532,077)	75,626,981	1,625,785	78,329,656	2,702,676	86,625,862	8,296,206	93,629,788	7,003,926	94,393,281	763,493

2009 Board Approved vs. 2009 Actual

The rate base for 2009 actuals decreased from the 2009 Board Approved in the amount of $1,532,077. The $944,844 decrease in the average book value in 2009 Actual from the Board Approved is mainly attributable to the removal of the stranded meters as a result of the Smart Meter program. Thunder Bay Hydro moved the stranded meters to the smart meter deferral account and annually reduced the deferral by the depreciation included in distribution rates attributable to the stranded meters. The 2009 actual working capital has also been reduced in comparison to the 2009 Board Approved due to the reduction in cost of power. This results in a decrease in the working capital allowance in the amount of $587,234.

2010 Actual vs. 2009 Actual

The rate base of $75,626,981 for 2010 increased by $1,625,785 over 2009. This increase is primarily the result of an increase in fixed assets of $1,786,620 due to capital expenditures. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides more details. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

2011 Actual vs. 2010 Actual

The rate base of $78,329,656 for 2011 increased by $2,702,676 over 2010. This increase is primarily the result of an increase in average fixed assets of $2,821,218 due to capital expenditures. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides more details. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

2012 Bridge Year vs. 2011 Actual

The rate base of $86,625,862 for the 2012 Bridge Year increased by $8,296,206. This increase is primarily the result in the increase of fixed assets, of which $8,131,647 represents the Smart Meter and related computer hardware and software that were rolled into Rate Base in 2012. The balance represents regular annual capital expenditures. The significant change in the working capital is primarily the change in the cost of power. OM&A increases also cause the working capital allowance to increase. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also provides more details. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1.

2013 Test Year (CGAAP) vs. 2012 Bridge Year

The rate base of $93,629,788 (CGAAP) for the 2013 Bridge Year increased by $7,003,926. The working capital allowance for 2013 Test Year has been reduced from 15% to 13% as per the Board's letter of April 12, 2012. Detailed information on the capital projects can be found in Exhibit 2, Tab 3, Schedule 2. Exhibit 2, Tab 2, Schedule 1 – Continuity Statements also

provides more details. Detailed calculations for the Working Capital Allowance are available in Exhibit 2, Tab 4, Schedule 1. A summary of Thunder Bay Hydro's cost of power and controllable expense used in the calculation of the working capital for the 2009 Board Approved, the 2009 Actual to 2011 Actual, the 2012 Bridge Year and the 2013 Test Year is shown below in Table 2-1.3.

Table 2-1.3 - Thunder Bay Hydro's Cost of Power and Controllable Expense

	2009 Board approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test (CGAAP)	2013 Test (MCGAAP)
Distribution Expenses - Operation	2,789,357	2,703,387	2,866,616	3,184,794	3,057,560	3,319,533	3,559,704
Distribution Expenses - Maintenance	3,049,733	3,177,750	3,300,110	2,786,514	3,885,577	3,109,691	3,951,962
Billing and Collecting	2,244,506	1,996,320	2,067,993	1,945,612	2,197,135	2,132,818	2,134,694
Community Relations	228,339	151,777	188,598	107,051	129,319	141,862	141,862
Administrative & General Expenses	3,623,127	3,820,604	3,927,036	4,035,999	4,499,372	4,714,091	4,894,193
Taxes Other than Income Taxes	170,284	178,000	60,000	3,752	-	-	-
Less : Capital Taxes within 6105	170,284	178,000	60,000	3,752	-	-	-
Less: Amortization included above	290,386	238,995	268,332	247,781	264,134	263,569	263,569
Total Eligible Distribution Expenses	11,644,677	11,610,842	12,082,021	11,812,190	13,504,829	13,154,426	14,418,846
Power Supply Expenses	78,227,629	74,346,574	78,449,275	85,711,366	96,806,595	97,020,439	97,020,439
Total Working Capital Expenses	89,872,307	85,957,416	90,531,296	97,523,555	110,311,424	110,174,865	111,439,285
Working Capital Allowance	13,480,846	12,893,612	13,579,694	14,628,533	16,546,714	14,322,732	14,487,107
Working Capital Allowance %	15%	15%	15%	15%	15%	13%	13%

2013 Test Year (MCGAAP) vs. 2013 Test Year (CGAAP)

Thunder Bay Hydro's modified capitalization policy has caused a significant increase to the 2013 Test Year. Thunder Bay hydro's assessment of the overhead costs that are not directly attributable to capital and therefore ineligible for allocation to capital assets as well as labour and other related costs of replacing meters and transformers in the field caused an increase to OM&A of $1,257,543.

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT and ACCUMULATED AMORTIZATION

Fixed asset continuity schedules for 2009 to 2013 CGAAP are outlined in tables 2-2.1 to 2.2-5 below. Further, table 2-2.6 provides a reconciliation between the schedules for 2009 to 2011 to the audited financial statements.

1 **CONTINUITY STATEMENTS**

Table 2-2.1 - Fixed Asset Continuity Schedule Year **2009 Actual**

			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)	765,366	-	-	765,366	(643,151)	(65,006)	-	(708,157)	57,210
CEC	1612	Land Rights (Formally known as Account 1906)				-				-	-
N/A	1805	Land	133,038			133,038				-	133,038
47	1808	Buildings	3,895,055	37,793		3,932,848	(1,574,491)	(71,842)		(1,646,334)	2,286,514
13	1810	Leasehold Improvements		33		33		(6)		(6)	28
47	1815	Transformer Station Equipment >50 kV				-				-	-
47	1820	Distribution Station Equipment <50 kV	8,099,698			8,099,698	(5,199,686)	(168,641)	-	(5,368,327)	2,731,371
47	1825	Storage Battery Equipment				-				-	-
47	1830	Poles, Towers & Fixtures	22,328,417	1,861,435		24,189,852	(7,775,197)	(742,565)	8,020	(8,509,742)	15,680,110
47	1835	Overhead Conductors & Devices	24,469,680	1,515,689		25,985,369	(11,408,994)	(1,085,345)	11,457	(12,482,882)	13,502,487
47	1840	Underground Conduit	11,697,672	615,523		12,313,195	(6,473,957)	(370,587)		(6,844,544)	5,468,651
47	1845	Underground Conductors & Devices	15,121,377	838,571		15,959,949	(7,633,146)	(441,441)		(8,074,587)	7,885,362
47	1850	Line Transformers	23,792,356	667,916		24,460,273	(13,340,346)	(797,794)	460,589	(13,677,551)	10,782,722
47	2320	ARO	512,186		-	512,186	(10,833)	(36,125)		(46,958)	465,228
47	1855	Services (Overhead & Underground)	17,652,429	1,037,326		18,689,755	(11,145,591)	(767,044)	3,437	(11,909,198)	6,780,557
47	1860	Meters	5,836,495	109,211	(4,936,080)	1,009,625	(3,029,787)	(437,220)	2,972,779	(494,228)	515,397
47	1860	Meters (Smart Meters)				-				-	-
N/A	1905	Land				-				-	-
47	1908	Buildings & Fixtures				-				-	-
13	1910	Leasehold Improvements				-				-	-
8	1915	Office Furniture & Equipment (10 years)	1,248,800	30,038		1,278,837	(1,073,095)	(36,748)		(1,109,843)	168,994
8	1915	Office Furniture & Equipment (5 years)				-				-	-
10	1920	Computer Equipment - Hardware	2,596,573	78,725		2,675,299	(2,446,384)	(82,798)		(2,529,181)	146,117
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				-				-	-
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		-	-	-			-	-	-
10	1930	Transportation Equipment	5,205,581	654,592	(403,229)	5,456,943	(3,895,934)	(319,448)	403,229	(3,812,153)	1,644,790
8	1935	Stores Equipment	63,417			63,417	(62,835)			(62,835)	582
8	1940	Tools, Shop & Garage Equipment	2,335,062	83,471		2,418,534	(2,009,400)	(70,171)		(2,079,571)	338,962
8	1945	Measurement & Testing Equipment	221,991			221,991	(66,540)	(22,199)		(88,740)	133,252
8	1950	Power Operated Equipment	3,583	124,234		127,817	(2,909)	(2,429)		(5,338)	122,479
8	1955	Communications Equipment	163,392			163,392	(160,611)	(796)		(161,407)	1,984
8	1955	Communication Equipment (Smart Meters)				-				-	-
8	1960	Miscellaneous Equipment				-				-	-
47	1975	Load Management Controls Utility Premises				-				-	-
47	1980	System Supervisor Equipment	515,152			515,152	(241,523)	(34,343)		(275,866)	239,286
47	1985	Miscellaneous Fixed Assets				-				-	-
47	1995	Contributions & Grants	(9,055,928)	(1,188,775)		(10,244,703)	1,561,900	367,800		1,929,700	(8,315,003)
47	1996	Hydro One Current & Voltage Transformer	548,576	345,595		894,171				-	894,171
WIP		Work in Process	962,145	314,551		1,276,696					1,276,696
		Total	**139,112,114**	**7,125,928**	**(5,339,309)**	**140,898,733**	**(76,632,510)**	**(5,184,748)**	**3,859,511**	**(77,957,748)**	**62,940,985**

Amortization allocation to other trial balance accounts & overheads	474,811
	(4,709,938)

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Table 2-2.2 - Fixed Asset Continuity Schedule **Year** **2010 Actual**

			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)	765,366	14,146		779,512	(708,157)	(30,321)		(738,478)	41,035
CEC	1612	Land Rights (Formally known as Account 1906)	-			-	-			-	-
N/A	1805	Land	133,038			133,038	-			-	133,038
47	1808	Buildings	3,932,848			3,932,848	(1,646,334)	(72,044)		(1,718,378)	2,214,470
13	1810	Leasehold Improvements	33			33	(6)	(17)		(22)	11
47	1815	Transformer Station Equipment >50 kV	-			-	-			-	-
47	1820	Distribution Station Equipment <50 kV	8,099,698	24,343		8,124,042	(5,368,327)	(168,820)		(5,537,147)	2,586,894
47	1825	Storage Battery Equipment	-			-	-			-	-
47	1830	Poles, Towers & Fixtures	24,189,852	2,273,733		26,463,586	(8,509,742)	(929,376)	62,095	(9,377,023)	17,086,563
47	1835	Overhead Conductors & Devices	25,985,369	1,712,841		27,698,210	(12,482,882)	(1,143,954)	88,709	(13,538,127)	14,160,083
47	1840	Underground Conduit	12,313,195	374,898		12,688,093	(6,844,544)	(370,423)		(7,214,967)	5,473,126
47	1845	Underground Conductors & Devices	15,959,949	1,034,322		16,994,271	(8,074,587)	(467,616)		(8,542,203)	8,452,068
47	1850	Line Transformers	24,460,273	1,406,560		25,866,833	(13,677,551)	(991,351)	244,207	(14,424,695)	11,442,138
47	2320	ARO	512,186		(350,443)	161,743	(46,958)	(40,750)		(87,708)	74,035
47	1855	Services (Overhead & Underground)	18,689,755	829,683		19,519,438	(11,909,198)	(810,803)	26,613	(12,693,388)	6,826,050
47	1860	Meters	1,009,625	67,771		1,077,396	(494,228)	(50,588)	(198,254)	(743,070)	334,326
47	1860	Meters (Smart Meters)				-	-			-	-
N/A	1905	Land				-	-			-	-
47	1908	Buildings & Fixtures				-	-			-	-
13	1910	Leasehold Improvements				-	-			-	-
8	1915	Office Furniture & Equipment (10 years)	1,278,837	65,653		1,344,490	(1,109,843)	(35,481)		(1,145,324)	199,166
8	1915	Office Furniture & Equipment (5 years)	-			-	-			-	-
10	1920	Computer Equipment - Hardware	2,675,299	58,137	(35,111)	2,698,325	(2,529,181)	(61,322)	35,111	(2,555,393)	142,932
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	-			-	-			-	-
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	-			-	-			-	-
10	1930	Transportation Equipment	5,456,943	762,485		6,219,429	(3,812,153)	(379,198)		(4,191,352)	2,028,077
8	1935	Stores Equipment	63,417			63,417	(62,835)			(62,835)	582
8	1940	Tools, Shop & Garage Equipment	2,418,534	23,204		2,441,738	(2,079,571)	(67,190)		(2,146,761)	294,977
8	1945	Measurement & Testing Equipment	221,991	34,833		256,825	(88,740)	(21,965)		(110,705)	146,120
8	1950	Power Operated Equipment	127,817	66,805		194,622	(5,338)	(16,008)		(21,345)	173,277
8	1955	Communications Equipment	163,392	23,141		186,533	(161,407)	(1,549)		(162,956)	23,577
8	1955	Communication Equipment (Smart Meters)	-			-	-			-	-
8	1960	Miscellaneous Equipment	-			-	-			-	-
47	1975	Load Management Controls Utility Premises	-			-	-			-	-
47	1980	System Supervisor Equipment	515,152			515,152	(275,866)	(34,343)		(310,210)	204,942
47	1985	Miscellaneous Fixed Assets	-			-	-			-	-
47	1995	Contributions & Grants	(10,244,703)	(2,499,649)		(12,744,352)	1,929,700	509,632		2,439,332	(10,305,020)
47	1996	Hydro One Current & Voltage Transformer	894,171	378,150		1,272,321	-	(35,240)		(35,240)	1,237,081
WIP		Work in Process	1,276,696	481,362		1,758,058	-	-			1,758,058
							-				
		Total	**140,898,733**	**7,132,420**	**(385,554)**	**147,645,600**	**(77,957,748)**	**(5,218,727)**	**258,481**	**(82,917,995)**	**64,727,605**

Amortization allocation to other trial balance accounts & overheads	535,492
	(4,683,235)

Table 2-2.3 - Fixed Asset Continuity Schedule **Year 2011 Actual**

			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)	779,512	40,316		819,829	(738,478)	(20,824)		(759,302)	60,526
CEC	1612	Land Rights (Formally known as Account 1906)	-			-	-			-	-
N/A	1805	Land	133,038			133,038	-			-	133,038
47	1808	Buildings	3,932,848			3,932,848	(1,718,378)	(72,044)		(1,790,422)	2,142,425
13	1810	Leasehold Improvements	33	2,473		2,507	(22)	(423)		(446)	2,061
47	1815	Transformer Station Equipment >50 kV	-			-	-			-	-
47	1820	Distribution Station Equipment <50 kV	8,124,042			8,124,042	(5,537,147)	(169,361)		(5,706,509)	2,417,533
47	1825	Storage Battery Equipment	-			-	-			-	-
47	1830	Poles, Towers & Fixtures	26,463,586	2,682,500		29,146,086	(9,377,023)	(995,308)	49,393	(10,322,937)	18,823,148
47	1835	Overhead Conductors & Devices	27,698,210	2,137,304		29,835,514	(13,538,127)	(1,203,746)	70,561	(14,671,312)	15,164,202
47	1840	Underground Conduit	12,688,093	926,862		13,614,955	(7,214,967)	(410,768)		(7,625,735)	5,989,220
47	1845	Underground Conductors & Devices	16,994,271	925,864		17,920,134	(8,542,203)	(464,959)		(9,007,162)	8,912,972
47	1850	Line Transformers	25,866,833	1,063,799		26,930,632	(14,424,695)	(1,031,084)	517,554	(14,938,225)	11,992,407
47	2320	ARO	161,743			161,743	(87,708)	17,795		(69,913)	91,830
47	1855	Services (Overhead & Underground)	19,519,438	705,597		20,225,035	(12,693,388)	(826,083)	21,168	(13,498,303)	6,726,732
47	1860	Meters	1,077,396	100,420		1,177,816	(743,070)	(86,526)	28,121	(801,475)	376,341
47	1860	Meters (Smart Meters)				-				-	-
N/A	1905	Land				-				-	-
47	1908	Buildings & Fixtures				-				-	-
13	1910	Leasehold Improvements				-				-	-
8	1915	Office Furniture & Equipment (10 years)	1,344,490	84,764		1,429,255	(1,145,324)	(38,918)		(1,184,242)	245,013
8	1915	Office Furniture & Equipment (5 years)				-				-	-
10	1920	Computer Equipment - Hardware	2,698,325	97,600		2,795,925	(2,555,393)	(61,075)		(2,616,468)	179,458
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				-				-	-
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)				-				-	-
10	1930	Transportation Equipment	6,219,429	399,566	(82,000)	6,536,995	(4,191,352)	(422,263)	82,000	(4,531,615)	2,005,380
8	1935	Stores Equipment	63,417			63,417	(62,835)			(62,835)	582
8	1940	Tools, Shop & Garage Equipment	2,441,738	29,425	(6,291)	2,464,872	(2,146,761)	(64,281)	4,694	(2,206,348)	258,524
8	1945	Measurement & Testing Equipment	256,825	13,637		270,461	(110,705)	(23,528)		(134,233)	136,229
8	1950	Power Operated Equipment	194,622			194,622	(21,345)	(19,176)		(40,521)	154,101
8	1955	Communications Equipment	186,533	48,777	(22,833)	212,477	(162,956)	(7,294)	22,806	(147,444)	65,033
8	1955	Communication Equipment (Smart Meters)				-				-	-
8	1960	Miscellaneous Equipment				-				-	-
47	1975	Load Management Controls Utility Premises				-				-	-
47	1980	System Supervisor Equipment	515,152			515,152	(310,210)	(34,343)		(344,553)	170,599
47	1985	Miscellaneous Fixed Assets				-				-	-
47	1995	Contributions & Grants	(12,744,352)	(2,958,053)		(15,702,405)	2,439,332	628,096		3,067,428	(12,634,977)
47	1996	Hydro One Current & Voltage Transformer	1,272,321	-		1,272,321	(35,240)	(50,893)		(86,133)	1,186,188
WIP		Work in Process	1,758,058	1,192,201		2,950,259	-	-			2,950,259
		Total	**147,645,600**	**7,493,052**	**(111,124)**	**155,027,528**	**(82,917,995)**	**(5,357,008)**	**796,298**	**(87,478,705)**	**67,548,823**

Amortization allocation to other trial balance accounts & overheads 583,422
(4,773,586)

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Table 2-2.4 - Fixed Asset Continuity Schedule Year **2012 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)	819,829	43,501	316,203	1,179,533	(759,302)	(93,245)	(134,052)	(986,599)	192,933
CEC	1612	Land Rights (Formally known as Account 1906)				-	-			-	-
N/A	1805	Land	133,038			133,038	-			-	133,038
47	1808	Buildings	3,932,848			3,932,848	(1,790,422)	(72,044)		(1,862,466)	2,070,381
13	1810	Leasehold Improvements	2,507	73,000		75,507	(446)	(4,004)		(4,450)	71,057
47	1815	Transformer Station Equipment >50 kV	-			-	-			-	-
47	1820	Distribution Station Equipment <50 kV	8,124,042		-	8,124,042	(5,706,509)	(169,361)		(5,875,870)	2,248,172
47	1825	Storage Battery Equipment	-			-	-			-	-
47	1830	Poles, Towers & Fixtures	29,146,086	4,076,237		33,222,322	(10,322,937)	(1,050,123)		(11,373,060)	21,849,262
47	1835	Overhead Conductors & Devices	29,835,514	3,582,045		33,417,559	(14,671,312)	(1,236,676)		(15,907,988)	17,509,571
47	1840	Underground Conduit	13,614,955	288,025		13,902,980	(7,625,735)	(406,911)		(8,032,646)	5,870,334
47	1845	Underground Conductors & Devices	17,920,134	1,263,182		19,183,316	(9,007,162)	(480,425)		(9,487,587)	9,695,729
47	1850	Line Transformers	26,930,632	1,409,100		28,339,732	(14,938,225)	(1,008,025)		(15,946,250)	12,393,482
47	2320	ARO	161,743			161,743	(69,913)	(9,752)		(79,665)	82,078
47	1855	Services (Overhead & Underground)	20,225,035	644,877		20,869,912	(13,498,303)	(818,041)		(14,316,344)	6,553,568
47	1860	Meters	1,177,816	14,857		1,192,673	(801,475)	(36,768)		(838,243)	354,430
47	1860	Meters (Smart Meters)	-	232,755	7,786,915	8,019,670	-	(576,026)	(1,245,627)	(1,821,653)	6,198,017
N/A	1905	Land	-			-	-			-	-
47	1908	Buildings & Fixtures	-			-	-			-	-
13	1910	Leasehold Improvements	-			-	-			-	-
8	1915	Office Furniture & Equipment (10 years)	1,429,255	71,352	(80,568)	1,420,039	(1,184,242)	(43,707)	57,802	(1,170,147)	249,892
8	1915	Office Furniture & Equipment (5 years)	-			-	-			-	-
10	1920	Computer Equipment - Hardware	2,795,925	222,408	(62,771)	2,955,562	(2,616,468)	(95,718)	68,836	(2,643,350)	312,212
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	-			-	-			-	-
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	-			-	-			-	-
10	1930	Transportation Equipment	6,536,995	464,723	(457,869)	6,543,849	(4,531,615)	(451,286)	457,869	(4,525,032)	2,018,817
8	1935	Stores Equipment	63,417			63,417	(62,835)	(582)		(63,417)	(0)
8	1940	Tools, Shop & Garage Equipment	2,464,872	51,585		2,516,457	(2,206,348)	(63,212)		(2,269,560)	246,897
8	1945	Measurement & Testing Equipment	270,461	23,873		294,334	(134,233)	(23,178)		(157,411)	136,924
8	1950	Power Operated Equipment	194,622			194,622	(40,521)	(18,964)		(59,485)	135,137
8	1955	Communications Equipment	212,477	28,012		240,489	(147,444)	(15,012)		(162,456)	78,033
8	1955	Communication Equipment (Smart Meters)	-			-	-			-	-
8	1960	Miscellaneous Equipment	-			-	-			-	-
47	1975	Load Management Controls Utility Premises	-			-	-			-	-
47	1980	System Supervisor Equipment	515,152	51,474	-	566,626	(344,553)	(34,343)		(378,896)	187,730
47	1985	Miscellaneous Fixed Assets	-			-	-			-	-
47	1995	Contributions & Grants	(15,702,405)	(2,022,925)		(17,725,330)	3,067,428	668,555		3,735,983	(13,989,347)
47	1996	Hydro One Current & Voltage Transformer	1,272,321	-		1,272,321	(86,133)	(50,893)		(137,026)	1,135,295
WIP		Work in Process	2,950,259	(1,681,465)		1,268,794	-	-		-	1,268,794
							-				
		Total	**155,027,528**	**8,836,615**	**7,501,910**	**171,366,052**	**(87,478,705)**	**(6,089,741)**	**(795,172)**	**(94,363,618)**	**77,002,434**

Smart Meter LTD Adjustment to be included in Dep	(1,393,943)
Sentinal Lighting Depreciation	
Amortization allocation to other t/b accounts and o/h	623,145
Hydro One Current & Voltage Transformer posted to separate account	50,893
	(6,809,646)

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Table 2-2.5 - Fixed Asset Continuity Schedule

Year **2013 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)	1,179,533	77,200	-	1,256,733	(986,599)	(97,865)	-	(1,084,464)	172,268
CEC	1612	Land Rights (Formally known as Account 1906)	-			-	-			-	-
N/A	1805	Land	133,038	-		133,038	-	-		-	133,038
47	1808	Buildings	3,932,848	3,303,500	(123,959)	7,112,389	(1,862,466)	(97,294)	58,640	(1,901,120)	5,211,268
47	1808	Garage		-		-	-			-	-
13	1810	Leasehold Improvements	75,507	-		75,507	(4,450)	(8,399)		(12,849)	62,658
47	1820	Distribution Equipment - ARO	-	-		-	-			-	-
47	1820	Distribution Equpment Normally Primary below 50 kV	8,124,042	-		8,124,042	(5,875,870)	(169,361)		(6,045,231)	2,078,811
47	1825	Storage Battery Equipment				-	-			-	-
47	1830	Poles, Towers & Fixtures	33,222,320	3,355,911	-	36,578,231	(11,373,060)	(1,115,044)	-	(12,488,105)	24,090,127
47	1835	Overhead Conductors & Devices	33,417,559	3,395,046	-	36,812,605	(15,907,987)	(1,302,012)	-	(17,210,000)	19,602,605
47	1840	Underground Conduit	13,902,980	246,571	-	14,149,551	(8,032,646)	(411,032)		(8,443,678)	5,705,873
47	1845	Underground Conductors & Devices	19,183,316	604,296	-	19,787,612	(9,487,587)	(504,694)		(9,992,281)	9,795,331
47	1850	Line Transformers	28,339,732	1,240,223	-	29,579,955	(15,946,250)	(1,030,780)	-	(16,977,030)	12,602,925
47	2320	ARO	161,743		-	161,743	(79,665)	(9,752)		(89,417)	72,326
47	1855	Services (Overhead & Underground)	20,869,912	924,514	-	21,794,426	(14,316,344)	(834,886)	-	(15,151,230)	6,643,196
47	1860	Meters	1,192,673	10,989		1,203,662	(838,243)	(37,122)		(875,365)	328,297
47	1860	Meters (Smart Meters)	8,019,670	172,162		8,191,832	(1,821,653)	(575,985)		(2,397,638)	5,794,194
N/A	1905	Land	-			-	-			-	-
47	1908	Buildings & Fixtures	-			-	-			-	-
13	1910	Leasehold Improvements	-			-	-			-	-
8	1915	Office Furniture & Equipment (10 years)	1,420,039	36,050		1,456,089	(1,170,147)	(42,182)		(1,212,329)	243,760
8	1915	Office Furniture & Equipment (5 years)	-	-		-	-	-		-	-
10	1920	Computer Equipment - Hardware	2,955,562	81,600	(44,200)	2,992,962	(2,643,350)	(117,338)	37,880	(2,722,808)	270,154
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	-			-	-			-	-
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	-			-	-	-		-	-
10	1930	Transportation Equipment	6,543,849	960,345	(363,511)	7,140,683	(4,525,032)	(517,947)	363,511	(4,679,468)	2,461,215
8	1935	Stores Equipment	63,417	-		63,417	(63,417)	-		(63,417)	(0)
8	1940	Tools, Shop & Garage Equipment	2,516,457	73,700		2,590,157	(2,269,560)	(115,323)		(2,384,883)	205,274
8	1945	Measurement & Testing Equipment	294,334	22,940		317,274	(157,411)	-		(157,411)	159,864
8	1950	Power Operated Equipment	194,622	13,400		208,022	(59,485)	-		(59,485)	148,537
8	1955	Communications Equipment	240,489	104,756		345,245	(162,456)	(19,622)		(182,078)	163,167
8	1955	Communication Equipment (Smart Meters)	-			-	-			-	-
8	1960	Miscellaneous Equipment	-			-	-			-	-
47	1975	Load Management Controls Utility Premises	-			-	-			-	-
47	1980	System Supervisor Equipment	566,626	2,077		568,703	(378,896)	(34,343)		(413,239)	155,463
47	1985	Miscellaneous Fixed Assets	-			-	-			-	-
	2440	Deferred Revenue	-			-	-			-	-
47	1995	Contributions & Grants	(17,725,330)	(1,044,834)		(18,770,164)	3,735,983	729,900		4,465,883	(14,304,281)
47	1996	Hydro One Current & Voltage Transformer	1,272,321	-		1,272,321	(137,026)	(50,893)		(187,919)	1,084,402
WIP		Work in Process	1,268,794	(190,812)		1,077,982	-	-		-	1,077,982
						-					
		Total	**171,366,050**	**13,389,634**	**(531,670)**	**184,224,014**	**(94,363,617)**	**(6,361,975)**	**460,031**	**(100,265,561)**	**83,958,453**

Amortization allocation to other t/b accounts and o/h	717,050
Hydro One Current & Voltage Transformer posted to separate account	50,583
	-
	(5,594,342)

Table 2-2.6 Reconciliation of Fixed Asset Continuity Schedules to Audited Financial Statements

	Cost				Accumulated Depreciation				
	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
2009 Actuals									
Balance per schedule	139,112,114	7,125,928	(5,339,309)	140,898,733	(76,632,510)	(5,184,748)	3,859,511	(77,957,748)	62,940,985
Add: Sentinel Lights	61,015	5,269		66,284	(12,874)	(2,737)		(15,610)	50,673
Less: Intangibles									
Computer Software	(765,366)			(765,366)	643,151	65,006		708,157	(57,210)
Hydro One Current & Voltage Transformer	(548,576)	(345,595)		(894,171)		-		-	(894,171)
Property, plant and equipment, net per audited financial statements	137,859,186	6,785,602	(5,339,309)	139,305,479	(76,002,233)	(5,122,479)	3,859,511	(77,265,202)	62,040,277
2010 Actuals									
Balance per schedule	140,898,733	7,132,420	(385,554)	147,645,600	(77,957,748)	(5,218,727)	258,481	(82,917,995)	64,727,605
Add: Sentinel Lights	66,284	5,447		71,731	(15,610)	(2,977)		(18,587)	53,144
Less: Intangibles									
Computer Software	(765,366)	(14,146)		(779,512)	708,157	30,321		738,478	(41,034)
Hydro One Current & Voltage Transformer	(894,171)	(378,150)		(1,272,321)	-	35,240		35,240	(1,237,081)
Property, plant and equipment, net per audited financial statements	139,305,480	6,745,572	(385,554)	145,665,498	(77,265,202)	(5,156,143)	258,481	(82,162,864)	63,502,634
2011 Actuals									
Balance per schedule	147,645,600	7,493,052	(111,124)	155,027,528	(5,357,008)	(5,357,008)	796,298	(87,478,705)	67,548,823
Add: Sentinel Lights	71,731	4,799		76,530	(18,587)	(3,238)		(21,826)	54,704
Less: Intangibles									
Computer Software	(779,512)	(40,316)		(819,829)	738,478	20,824		759,302	(60,527)
Hydro One Current & Voltage Transformer	(1,272,321)			(1,272,321)	35,240	50,893		86,133	(1,186,188)
Add: Work in Progress Associated with Non-Wires		52,664		52,664					52,664
Property, plant and equipment, net per audited financial statements	145,665,497	7,510,199	(111,124)	153,064,572	(4,601,878)	(5,288,530)	796,298	(86,655,096)	66,409,477

GROSS ASSET TABLE

Table 2-2.7-Gross Asset Continuity Schedule Summary **Year** **2009-2013 CGAAP 2013 MCGAAP**

CCA Class	OEB	Description	2009 Board Approved	2009 Actual	Variance from 2009 OEB Approved	2010 Actual	Variance from 2009 Actual	2011 Actual	Variance from 2010 Actual	2012 Bridge CGAAP	Variance from 2011 Actual	2013 Test CGAAP	Variance from 2012 Bridge	2013 Test MCGAAP	Variance from 2013 CGAAP
12	1611	Computer Software (Formally known as Account 1925)	775,496	765,366	(10,130)	779,512	14,146	819,829	40,316	1,179,533	359,704	1,256,733	77,200	1,256,733	-
CEC	1612	Land Rights (Formally known as Account 1906)	-	-	-	-	-	-	-	-	-	-	-	-	-
Land and Buildings													-		-
N/A	1805	Land	133,038	133,038	-	133,038	-	133,038	-	133,038	-	133,038	-	133,038	-
47	1808	Buildings	4,029,355	3,932,848	(96,507)	3,932,848	-	3,932,848	-	3,932,848	-	3,812,389	(120,459)	3,812,389	-
47	1808	Garage										3,300,000	3,300,000	3,300,000	-
13	1810	Leasehold Improvements	-	33	33	33	-	2,507	2,473	75,507	73,000	75,507	-	75,507	-
		Sub-Total Land and Buildings	4,162,392	4,065,918	(96,474)	4,065,918	-	4,068,392	2,473	4,141,392	73,000	7,320,933	3,179,541	7,320,933	-
47	1815	Transformer Station Equipment >50 kV	-	-	-	-	-	-	-	-	-	-	-	-	-
DS															
47	1820	Distribution Station Equipment <50 kV	8,099,698	8,099,698	-	8,124,042	24,343	8,124,042	-	8,124,042	-	8,124,042	-	8,125,921	1,879
47	1820	Distribution Station Equipment ARO												45,125	45,125
		Sub-Total DS													
47	1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
Poles and Wires															
47	1830	Poles, Towers & Fixtures	22,598,260	24,189,852	1,591,592	26,463,586	2,273,733	29,146,086	2,682,500	33,222,322	4,076,237	36,578,231	3,355,909	36,074,505	(503,726)
47	1835	Overhead Conductors & Devices	26,085,933	25,985,369	(100,564)	27,698,210	1,712,841	29,835,514	2,137,304	33,417,559	3,582,045	36,812,605	3,395,046	35,919,190	(893,415)
47	1840	Underground Conduit	12,177,358	12,313,195	135,837	12,688,093	374,898	13,614,955	926,862	13,902,980	288,025	14,149,551	246,571	14,109,113	(40,437)
47	1845	Underground Conductors & Devices	16,186,138	15,959,949	(226,189)	16,994,271	1,034,322	17,920,134	925,864	19,183,316	1,263,182	19,787,612	604,296	19,699,141	(88,471)
		Sub-Total Poles and Wires													
Line Transformers															
47	1850	Line Transformers	25,089,800	24,460,273	(629,528)	25,866,833	1,406,560	26,930,632	1,063,799	28,339,732	1,409,100	29,579,955	1,240,223	29,098,595	(481,360)
47	2320	ARO	-	512,186	512,186	161,743	(350,443)	161,743	-	161,743	-	161,743	-	161,743	(0)
		Sub-Total Line Transformers													
		Serv													
47	1855	Services (Overhead & Underground)	18,611,502	18,689,755	78,252	19,519,438	829,683	20,225,035	705,597	20,869,912	644,877	21,794,426	924,514	21,487,435	(306,992)
47	1860	Meters	6,027,261	1,009,625	(5,017,635)	1,077,396	67,771	1,177,816	100,420	1,192,673	14,857	1,203,662	10,989	1,217,673	14,011
47	1860	Meters (Smart Meters)	-	-	-	-	-	-	-	8,019,670	8,019,670	8,191,832	172,162	8,138,044	(53,788)
N/A	1905	Land	-	-	-	-	-	-	-	-	-	-	-	-	-
47	1908	Buildings & Fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-
13	1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-
8	1915	Office Furniture & Equipment (10 years)	1,351,788	1,278,837	(72,951)	1,344,490	65,653	1,429,255	84,764	1,420,039	(9,216)	1,456,089	36,050	1,456,089	-
8	1915	Office Furniture & Equipment (5 years)	-	-	-	-	-	-	-	-	-	-	-	-	-
10	1920	Computer Equipment - Hardware	2,812,163	2,675,299	(136,864)	2,698,325	23,026	2,795,925	97,600	2,955,562	159,637	2,992,962	37,400	2,992,962	-
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	-	-	-	-	-	-	-	-	-	-	-
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	-	-	-	-	-	-	-	-	-	-	-
10	1930	Transportation Equipment	5,695,964	5,456,943	(239,021)	6,219,429	762,485	6,536,995	317,566	6,543,849	6,854	7,140,683	596,834	7,140,683	-
8	1935	Stores Equipment	63,417	63,417	-	63,417	-	63,417	-	63,417	-	63,417	-	63,417	-
8	1940	Tools, Shop & Garage Equipment	2,332,649	2,418,534	85,884	2,441,738	23,204	2,464,872	23,134	2,516,457	51,585	2,590,157	73,700	2,590,157	-
8	1945	Measurement & Testing Equipment	221,724	221,991	267	256,825	34,833	270,461	13,637	294,334	23,873	317,274	22,940	317,274	-
8	1950	Power Operated Equipment	133,583	127,817	(5,766)	194,622	66,805	194,622	-	194,622	-	208,022	13,400	208,022	-
8	1955	Communications Equipment	163,392	163,392	-	186,533	23,141	212,477	25,944	240,489	28,012	345,245	104,756	345,245	-
8	1955	Communication Equipment (Smart Meters)	-	-	-	-	-	-	-	-	-	-	-	-	-
8	1960	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
47	1975	Load Management Controls Utility Premises	-	-	-	-	-	-	-	-	-	-	-	-	-
47	1980	System Supervisor Equipment	515,152	515,152	-	515,152	-	515,152	-	566,626	51,474	568,703	2,077	566,626	(2,077)
47	1985	Miscellaneous Fixed Assets	-	-	-	-	-	-	-	-	-	-	-	-	-
	2440	Deferred Revenue										-		(989,985)	(989,985)
47	1995	Contributions & Grants	(8,926,024)	(10,244,703)	(1,318,679)	(12,744,352)	(2,499,649)	(15,702,405)	(2,958,053)	(17,725,330)	(2,022,925)	(18,770,164)	(1,044,834)	(17,725,330)	1,044,834
47	1996	Hydro One Current & Voltage Transformer	1,355,873	894,171	(461,702)	1,272,321	378,150	1,272,321	-	1,272,321	-	1,272,321	-	1,272,321	-
WIP		Work in Process	494,000	1,276,696	782,696	1,758,058	481,362	2,950,259	1,192,201	1,268,794	(1,681,465)	1,077,982	(190,812)	983,556	(94,426)
										-	-		-	-	-
		Total	**146,027,521**	**140,898,733**	**(5,128,788)**	**147,645,600**	**6,746,867**	**155,027,528**	**7,381,928**	**171,366,052**	**16,338,525**	**184,224,014**	**12,857,962**	**181,875,186**	**(2,348,828)**

VARIANCE ANALYSIS ON GROSS ASSETS

The Gross Asset Variance analysis for the variances highlighted in Table 2-2.7 of Exhibit 2, Tab 2, Schedule 2 is provided as follows:

2009 Board Approved vs. 2009 Actual

The 2009 actual expenditures were less than the 2009 Board Approved Fixed Assets due to the removal of stranded assets related to the Smart Meter Project of $4,936,080. Buildings were $96,507 less than the 2009 Board Approved due to the fact that $45,000 of these expenditures was more appropriately classified as equipment. The remainder related to the deferral of a project for $25,000 and achieving cost savings on amounts budgeted. Computer hardware was $136,864 less than 2009 Board Approved due to hardware disposals of $75,000 that were not budgeted for, a Blade Server of $40,000 was not purchased, and the deferral of software purchase of $10,000. Transportation equipment was less than 2009 Board Approved due to $164,000 of removals. Tools, Shop and Garage Equipment was greater than the 2009 Board Approved by $85,884 due to the movement of capital purchases from buildings above. The Hydro One Current & Voltage Transformer was $461,702 less than the 2009 Board Approved Budget due to the fact that 2 stations were not completed in 2009 therefore costs were included in work in progress and subsequently capitalized in 2010 when the projects were complete.

2009 Actual vs. 2010 Actual

The variances in gross assets for 2009 Actual compared to 2010 Actual are the result of capital expenditures in 2010. Distribution Plant investment was in line with the 20-year capital plan. The transportation equipment included the purchase of 2 single bucket trucks, 2 double bucket trucks and stringing system. The Hydro One Current & Voltage Transformer was completed in 2010.

2010 Actual vs. 2011 Actual

The variances in gross assets for 2010 Actual compared to 2011 Actual are the result of capital expenditures in 2011. This included the Distribution Plant investment, computer hardware purchases of laptops, desktop computers, servers, wireless network and printers.

Transportation equipment included 3 crew cabs, a backhoe loader and a Radial Boom Derrick (RBD).

2011 Actual vs . 2012 Bridge Year

The increase for 2012 is a result of capital spending during the year and the inclusion of Thunder Bay Hydro's Smart Meter Costs in rate base. This included Thunder Bay Hydro's increase in Distribution Plant investment; computer hardware, including desktop computers, servers, network switches/router, firewall appliances and fibre optic cabling; and transportation equipment, including replacement crew cabs, a dump box, a mini single bucket and cab and chassis for RBD.

2012 Bridge Year vs. 2013 Test Year CGAAP

The variances in gross assets for the 2012 Bridge Year compared to the 2013 Test Year are the result of capital expenditures in 2013. This included Thunder Bay Hydro's increase in Distribution Plant investment as outlined in Thunder Bay Hydro's 20 year capital plan. Transportation equipment includes replacement of crew cabs, a double bucket truck, and the RBD portion of the truck started in 2012 above. The 2013 budget includes $3.3M for the construction of a new garage. As a result, the old garage costs of $120,459 originally capitalized in buildings have been removed.

2012 Bridge Year vs. 2013 Test Year MCGAAP

See Table 2-2.8 below.

Table 2-2.8 -Reconciliation of 2013 Gross Assets CGAAP to MCGAAP

Total Gross Assets CGAAP		184,224,014
Burdens removed		(1,657,646)
Additional costs capitalized		439,781
Net change in contributions	(1,044,834)	
	(989,985)	54,849
Net change in WIP	(190,812)	
	(285,238)	(94,426)
Net change in Asset Removals	(531,670)	
	(1,623,058)	(1,091,388)
Total Gross Assets MCGAAP		181,875,184

ACCUMULATED DEPRECIATION TABLE

Table 2-2.9 - Accumulated Depreciation Continuity Schedule Summa **Year** **2009-2013 CGAAP 2013 MCGAAP**

CCA Class	OEB	Description	2009 Board Approved	2009 Actual	Variance from 2009 OEB Approved	2010 Actual	Variance from 2009 Actual	2011 Actual	Variance from 2010 Actual	2012 Bridge CGAAP	Variance from 2011 Actual	2013 Test CGAAP	Variance from 2012 Bridge	2013 Test MCGAAP	Variance from 2013 CGAAP
12	1611	Computer Software (Formally known as Account 1925)	(725,267)	(708,157)	17,110	(738,478)	(30,321)	(759,302)	(20,824)	(986,599)	(227,297)	(1,084,464)	(97,865)	(1,038,525)	45,939
CEC	1612	Land Rights (Formally known as Account 1906)	-	-	-	-	-	-	-	-	-	-	-	-	-
Land and Buildings															
N/A	1805	Land	-	-	-	-	-	-	-	-	-	-	-	-	-
47	1808	Buildings	(1,662,183)	(1,646,334)	15,849	(1,718,378)	(72,044)	(1,790,422)	(72,044)	(1,862,466)	(72,044)	(1,875,870)	(13,404)	(1,875,870)	-
47	1808	Garage										(25,250)		(25,250)	-
13	1810	Leasehold Improvements	-	(6)	(6)	(22)	(17)	(446)	(423)	(4,450)	(4,004)	(12,849)	(8,399)	(12,849)	-
Sub-Total Land and Buildings															
47	1815	Transformer Station Equipment >50 kV	-	-	-	-	-	-	-	-	-		-		-
47	1820	Distribution Station Equipment <50 kV	(5,843,964)	(5,368,327)	475,637	(5,537,147)	(168,820)	(5,706,509)	(169,361)	(5,875,870)	(169,361)	(6,045,231)	(169,361)	(6,195,697)	(150,466)
47	1820	Distribution Station Equipment - ARO										-		(7,386)	(7,386)
47	1825	Storage Battery Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
47	1830	Poles, Towers & Fixtures	(10,346,920)	(8,509,742)	1,837,178	(9,377,023)	(867,281)	(10,322,937)	(945,915)	(11,373,060)	(1,050,123)	(12,488,105)	(1,115,044)	(11,885,879)	602,225
47	1835	Overhead Conductors & Devices	(12,323,341)	(12,482,882)	(159,541)	(13,538,127)	(1,055,245)	(14,671,312)	(1,133,185)	(15,907,988)	(1,236,676)	(17,210,000)	(1,302,011)	(16,031,897)	1,178,103
47	1840	Underground Conduit	(6,584,277)	(6,844,544)	(260,267)	(7,214,967)	(370,423)	(7,625,735)	(410,768)	(8,032,646)	(406,911)	(8,443,678)	(411,032)	(8,140,592)	303,086
47	1845	Underground Conductors & Devices	(8,230,501)	(8,074,587)	155,914	(8,542,203)	(467,616)	(9,007,162)	(464,959)	(9,487,587)	(480,425)	(9,992,281)	(504,694)	(9,842,769)	149,512
47	1850	Line Transformers	(14,470,435)	(13,677,551)	792,884	(14,424,695)	(747,145)	(14,938,225)	(513,530)	(15,946,250)	(1,008,025)	(16,977,030)	(1,030,780)	(16,230,787)	746,243
47	2320	ARO		(46,958)	(46,958)	(87,708)	(40,750)	(69,913)	17,795	(79,665)	(9,752)	(89,417)	(9,752)	(89,417)	-
47	1855	Services (Overhead & Underground)	(9,700,983)	(11,909,198)	(2,208,215)	(12,693,388)	(784,190)	(13,498,303)	(804,915)	(14,316,344)	(818,041)	(15,151,230)	(834,886)	(14,417,115)	734,115
47	1860	Meters	(3,294,213)	(494,228)	2,799,985	(743,070)	(248,842)	(801,475)	(58,405)	(838,243)	(36,768)	(875,365)	(37,122)	(853,180)	22,185
47	1860	Meters (Smart Meters)	-	-	-	-	-	-	-	(1,821,653)	(1,821,653)	(2,397,638)	(575,985)	(2,358,892)	38,746
N/A	1905	Land	-	-	-	-	-	-	-	-	-	-	-	-	-
47	1908	Buildings & Fixtures	-	-	-	-	-	-	-	-	-	-	-	-	-
13	1910	Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-
8	1915	Office Furniture & Equipment (10 years)	(1,121,274)	(1,109,843)	11,431	(1,145,324)	(35,481)	(1,184,242)	(38,918)	(1,170,147)	14,095	(1,212,329)	(42,182)	(1,212,329)	-
8	1915	Office Furniture & Equipment (5 years)	-	-	-	-	-	-	-	-	-	-	-	-	-
10	1920	Computer Equipment - Hardware	(2,681,274)	(2,529,181)	152,093	(2,555,393)	(26,212)	(2,616,468)	(61,075)	(2,643,350)	(26,882)	(2,722,808)	(79,458)	(2,787,472)	(64,664)
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	-	-	-	-	-	-	-	-	-	-	-
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	-	-	-	-	-	-	-	-	-	-	-
10	1930	Transportation Equipment	(4,132,591)	(3,812,153)	320,438	(4,191,352)	(379,198)	(4,531,615)	(340,263)	(4,525,032)	6,583	(4,679,468)	(154,436)	(4,390,754)	288,714
8	1935	Stores Equipment	(63,417)	(62,835)	582	(62,835)	-	(62,835)	-	(63,417)	(582)	(63,417)	-	(63,417)	-
8	1940	Tools, Shop & Garage Equipment	(2,078,955)	(2,079,571)	(617)	(2,146,761)	(67,190)	(2,206,348)	(59,586)	(2,269,560)	(63,212)	(2,384,883)	(115,323)	(2,338,753)	46,129
8	1945	Measurement & Testing Equipment	(78,875)	(88,740)	(9,864)	(110,705)	(21,965)	(134,233)	(23,528)	(157,411)	(23,178)	(157,411)	-	(182,782)	(25,371)
8	1950	Power Operated Equipment	(11,381)	(5,338)	6,044	(21,345)	(16,008)	(40,521)	(19,176)	(59,485)	(18,964)	(59,485)	-	(80,243)	(20,758)
8	1955	Communications Equipment	(163,392)	(161,407)	1,984	(162,956)	(1,549)	(147,444)	15,512	(162,456)	(15,012)	(182,078)	(19,622)	(171,902)	10,176
8	1955	Communication Equipment (Smart Meters)	-	-	-	-	-	-	-	-	-	-	-	-	-
8	1960	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
47	1975	Load Management Controls Utility Premises	-	-	-	-	-	-	-	-	-	-	-	-	-
47	1980	System Supervisor Equipment	(70,652)	(275,866)	(205,214)	(310,210)	(34,343)	(344,553)	(34,343)	(378,896)	(34,343)	(413,239)	(34,343)	(413,239)	0
47	1985	Miscellaneous Fixed Assets	-	-	-	-	-	-	-	-	-	-	-	-	-
	2440	Deferred revenue										-		12,712	12,712
47	1995	Contributions & Grants	1,921,900	1,929,700	7,800	2,439,332	509,632	3,067,428	628,096	3,735,983	668,555	4,465,883	729,900	4,192,942	(272,941)
47	1996	Hydro One Curren & Voltage Transformer	(28,476)	-	28,476	(35,240)	(35,240)	(86,133)	(50,893)	(137,026)	(50,893)	(187,919)	(50,893)	(179,437)	8,482
WIP		Work in Progress	-	-	-	-	-	-	-	-	-	-	-	-	-
	etc.													-	-
		Total	**(81,690,469)**	**(77,957,748)**	**3,732,721**	**(82,917,995)**	**(4,960,246)**	**(87,478,705)**	**(4,560,710)**	**(94,363,618)**	**(6,884,913)**	**(100,265,561)**	**(5,876,693)**	**(96,620,780)**	**3,644,781**

VARIANCE ANALYSIS ON ACCUMULATED DEPRECIATION

Changes in accumulated amortization are directly affected by changes in fixed assets due to additions, the removal of fully depreciated assets from the grouped asset classes, and the disposition of identified assets.

Table 2-2.9 shows the changes in accumulated depreciation from 2009 Actual to the 2013 Test Year. The change in accumulated depreciation is a result of capital expenditures, amortization expense each year, and write-offs of fully-amortized assets as appropriate over the four year period.

Variance from 2009 OEB Approved

A variance in the 2009 Actual vs. 2009 Board Approved is a result of Distribution plant accumulated depreciation being lower mainly due to the removal of the accumulated depreciation related to the stranded assets removed for the Smart Meter Project in the amount of $2,913,896. Additionally, lower than projected 2008 additions and higher than projected asset removals for computer hardware and transportation equipment contributed to the variance in the accumulated depreciation.

Variance from 2009 Actual

The 2010 actual represents regular amortization on assets. The only significant variance is that no Transportation Equipment was disposed of during the year where as 2009 included $403,229.

Variance from 2010 Actual

The 2011 actuals represent regular amortization on assets. The only significant variances from the previous year were transformer disposals increased by $273,347 and transportation equipment disposals increased by $82,000.

Variance from 2011 Actual

From 2011 to 2012, $1,393,943 of accumulated depreciation is related to the Smart Meter assets being transferred to rate base as of January 1, 2012. Further, transportation equipment disposals were $375,869 higher than the previous period.

Variance from 2012 Bridge

From 2012 to 2013 CGAAP amortization represents amounts calculated using the current APH depreciation rates. There are no anomalies from 2012.

Variance from 2013 Test CGAAP

Thunder Bay Hydro has used the Kinectric's Depreciation Study as a guide to amend the depreciation rates. Thunder Bay Hydro's assessment resulted in longer asset lives causing a significantly lower annual depreciation. As well, asset removals are now accounted for as they occur.

Please refer to Exhibit 4, Tab 2, Schedule 7 for details of annual amortization expense for each asset account.

CAPITAL BUDGET

Thunder Bay Hydro's Asset Management Plan identifies the capital projects required over a 20 year period based on the best available information for each year. The capital budget forecast is influenced significantly by condition data that is collected each year on aging infrastructure and as such, Thunder Bay Hydro may be required to adjust the capital project forecast as the knowledge of its system needs increases. As provided in Exhibit 2, Tab 3, Schedule 2, a significant portion of Thunder Bay Hydro's capital spending are customer or municipal driven. All proposed capital projects for the 2012 Bridge Year and 2013 Test Year have taken Construction Work in Progress ("CWIP") into account and all projects completed and in service that year have been capitalized. Details of Thunder Bay Hydro's capital budget for these periods are provided in tables below.

Provincial Sales Tax Impact

The Provincial Sales Tax ("PST") and the Federal Goods and Services Tax were harmonized into the Harmonized Sales Tax ("HST") effective July 1, 2010. As a result of this harmonization Thunder Bay Hydro allocated into account 1592, the net reduction in costs in the form of Input Tax Credits ("ITCs"). This net reduction is the result of cost decreases from the receipt of additional ITCs on the purchases of goods and services previously subject to PST that become subject to the HST.

Thunder Bay Hydro has identified and accounted for the HST changes in the capital budget process and in the budgeted OM&A to reflect the implementation of the HST. Thunder Bay Hydro confirms that the steps taken in the budgeting process ensures that capital and OM&A costs contained in the 2013 Test Year exclude all impacts of PST previously embedded in costs for the historical years.

Introduction

Thunder Bay Hydro has been, and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital spending. The capital spending for the 2012 Bridge Year and the 2013 Test Year is broken down by account and by project in Exhibit 2, Tab 3, Schedule 2. Below in Table 2-3.1, is an analysis of Thunder Bay Hydro's capital spending from 2009 to 2013.

Table 2-3.1 – Analysis of Thunder Bay Hydro's Capital Spending

Year	Total Distribution Plant ($)	Capital Contributions	Net Distribution Plant	General Plant	Total Capital net of Contribution	$ Increase / (Decrease)	% Increase / (Decrease)
2007 CGAAP	$5,664,211	($953,374)	$4,710,837	$478,269	$5,189,106	$0	0%
2008 CGAAP	$7,576,600	($1,425,904)	$6,150,696	$806,782	$6,957,478	$1,768,372	34%
2009 BA CGAAP	$7,213,623	($650,000)	$6,563,623	$990,000	$7,553,623	$596,145	9%
2009 CGAAP	$7,885,993	($1,188,775)	$6,697,218	$971,093	$7,668,310	$114,687	2%
2010 CGAAP	$9,028,436	($2,499,649)	$6,528,787	$1,048,405	$7,577,192	($91,119)	(1%)
2011 CGAAP	$10,474,009	($2,958,053)	$7,515,956	$716,559	$8,232,515	$655,323	9%
2012 CGAAP	$9,881,086	($2,022,925)	$7,858,161	$978,454	$8,836,615	$604,100	7%
2013 CGAAP	$9,758,900	($1,044,834)	$8,714,066	$4,675,568	$13,389,634	$4,553,019	52%
2013 MCGAAP	$8,452,186	($989,985)	$7,462,201	$4,669,991	$12,132,192	$3,295,577	37%

In 2007, Thunder Bay Hydro recognized a need to change some of its policies and processes, as well as make organizational changes, in order to gain efficiencies. Some of those changes included its approach to new connections, development of a 20-year capital plan, a capital program focus, and the use of risk assessments, voltage conversion from 4kV to 25kV, new outage management policy, forestry management, and PCB removal.

The 2007 capital budget was set slightly lower than 2006 as only one significant capital rebuild project (Frankwood Rebuild) was undertaken using Thunder Bay Hydro's change in methodology. Actual capital spending for 2007 came in lower than budgeted, as the Frankwood project was substantially under budget by $812,193. This variance in budget vs. actuals was due to two factors. Firstly, the project was anticipated to cost approximately $1.2M however, given that this was the first very large-scale complete rebuild undertaken and significant uncertainty with regard to potential customer issues, a sizeable contingency was included in the budgeted amount. Secondly, new standards were purchased in 2007 that facilitated the construction of this project with a lower cost of materials, as well as less labour. A one outage

per year per customer policy was introduced facilitating taking outages on this project, which also helped to expedite its execution.

In 2008, Thunder Bay Hydro's capital spending increased primarily to address the asset conditions. Actual expenditures for net capital plant came in at $7M. Capital projects included revenue metering upgrades at the Fort William Transformer Station and an underground cable replacement project. As well, three area rebuild projects were completed as part of the plan to decommission one of the oldest substations, John Street Substation.

For 2009, capital program spending continued to increase for distribution plant replacement programs and customer and safety driven projects at a slightly higher level than the 2009 Board approved amount. The increase in spending is as a result of three major area rebuild projects and one underground cable replacement project was completed. The expenditures for the net distribution plant capital replacement programs came in at $6.7M. A budget of just under $1M for capital tools, buildings and fixtures was almost fully spent. Expenditures included a double bucket and replacement radial boom derrick to help meet the increased work due to capital programs.

Capital program spending decreased slightly in 2010. The budget included several major distribution plant rebuild projects, including a major underground cable replacement project; however, due to a major storm in the third quarter of the year, the planned capital replacement program could not be completed. Also, capital tool expenditures came in under budget.

In 2011, the net capital spending increased by $655,000 from 2010. In 2011, a large underground cable replacement project in one of the older subdivisions was completed. A partial discharge cable testing program was initiated to verify the condition of the Fort William Transformer Station (FWTS) egress cables as well. The results of that testing indicated that a significant amount of the cables needed to be immediately replaced; these replacements were started in 2011. Customer and safety driven projects came in over budget once again due to higher than anticipated customer driven requests, including major line relocation for a city road widening project. General Service customer requests were also well above the budgeted amount. Capital tool expenditures included the purchase of a new backhoe and a radial boom derrick that had been rented for a part of the year. The funding budgeted to start the process of replacing our Fleet Garage was not spent as the project was put on hold.

The forecast for 2012 is to continue with Thunder Bay Hydro's 20-year capital plan. The remaining overhead rebuild projects should be completed before the end of the third quarter, which will allow for the decommissioning of the Mary Street Substation by the end of the year. At the half-way mark of the year, 43% of the budget has been spent, with the majority of work usually completed in the last half of the year. Scheduled cable replacement at the Fort William Transmission Station is ongoing. The partial discharge cable testing at the Algoma Street Substation was stopped due to major cable failures after testing; failed cable replacement work has been completed at the substation. General Service customer requests are trending to come in above budget with 100% of the budget spent with 58% of the year lapsed. Capital tool expenditures include the purchase of a new dump truck and radial boom derrick cab & chassis, with the remainder of the unit to be purchased in 2013.

In 2013, the capital expenditures are driven by the need to replace old infrastructure, decommissioning, and renewable generation. Thunder Bay Hydro's capital program will include rebuild and voltage conversion projects to allow for the decommissioning of Thunder Bay Hydro's third 4kV substation (Brock Street Substation) by the end of 2013. General Service customer requests are projected to still be strong, in addition to an increase in residential subdivisions for 2013. It is also anticipated that the connection of a 16MW wind park will require Renewable Enabling Improvements to Thunder Bay Hydro's system. Capital tool expenditures will increase to include a new material handler, single bucket truck, and new radial boom derrick for the chassis purchased in 2012. 2013 will also include a new maintenance facility for $3.3M, which is explained in more detail below.

<u>New Maintenance Facility Construction Project</u>

Thunder Bay Hydro will employ the services of a General Contractor to demolish the cold storage section (25mL x 13mW x 5mH) of the existing 1932 vintage fleet maintenance building and design and build a new 27mL x 27mW x 9mH stand-alone maintenance facility as per the general requirements of the utility.

The project's budget has been set at $3.3M based on the current cost of commercial construction in Thunder Bay as provided by a local architecture and engineering company.

Completion of this construction project is anticipated to be by August 2013.

This project is necessary as the existing maintenance facility and cold storage (Annex) is 80 years old and has numerous areas of concern; most of which are detailed below:

- Current maintenance facility ventilation system does not meet today's minimum building code requirements
- Current maintenance facility does not comply with current fire code regulations as there is no sprinkler system, annunciated fire alarm panel, field addressable heat and smoke detection devices. Pricing to upgrade to current standards was $75,000.
- Current maintenance facility does not comply with accessibility standards requirements
- Severely sloped concrete floor exists throughout the main vehicle repair area (outside walls to centre of room) so much so that mechanics creepers and transmission dollies have to be blocked or they will roll to the centre of the floor on their own. Ground penetrating radar has confirmed that a second floor exists at depth under the current floor. Pricing received to remove and replace the floors was $120,000.
- The maintenance garage and Annex has potential structural issues as the exterior / interior walls are cracking, the outside walls are bowed, the wall footings are separating from the floors.
- The west brick wall of the main repair facility is deteriorated to a chalk like medium due to a pre-1970's fire (no drilling is currently allowed on this wall)
- Either the concrete floor is sinking or the foundation is lifting throughout the entire building, as evident with the ½"+ cracks and concrete patch work that exists around the entire perimeter of the interior walls.
- The current maintenance facility has an in-floor ladder type catch trough for water, oil, and sediment collection that was connected to the city's sewer system (since blanked off). Although oil absorbent matting/pads are used throughout the various levels of this containment trough, there is likely cracks in the concrete which may be leaching contaminates under the floor.
- Annex roof is leaking is numerous locations (repair cost for replacing the flat Annex roof is $50,000).
- Designated substances exist throughout the maintenance facility (vermiculite asbestos within the east wall of the structure and lead based paint on all interior brick walls).

- The overhead vehicle entry doors are no longer manufactured. Cost to replace all three doors is $16,500.
- No security system or unauthorized entry monitoring exists in the current maintenance facility. Cost to install a complete security (video, motion, door entry) system is $30,000.
- Interior ceiling height of the current maintenance facility at 17 feet is too low and lifting the large 13+ foot high line trucks off the ground to complete repair work is not possible

Thunder Bay Hydro investigated the following options in lieu of recommending the new maintenance facility construction project:

- Refurbishing / repairing the existing structural issues and raising the ceiling height of the old maintenance building was not recommended by a local architectural / engineering company as a viable option due to the building age. This option was not operationally acceptable as it would have adversely impacted the mechanical, lines and other work groups during the proposed building rehabilitation.
- Utilizing external repair services / facilities for all mechanical / welding needs was not a viable option as it would have mandated the elimination of the Thunder Bay Hydro mechanical work force and increased equipment downtimes because third party technicians are not familiar with the Utility's specialty equipment, the utility would not receive preferential treatment or priority over other customers and because trained employees would be needed to shuttle vehicles to and from these off site shops.
- Acquisition of another building off site was also investigated; however the logistics of shuttling personnel to and from the other site back to the Operations Centre, vehicle security concerns, work site supervision, general convenience and repair efficiencies were too substantial to make this a viable consideration

The proposed design-build solution involves the demolition of the Annex and utilization of the newly created real-estate foot print to construct a new fire / building code compliant, environmentally sound, ergonomically friendly, safe and efficient maintenance facility that will allow Thunder Bay Hydro to efficiently repair all of their fleet vehicles for another 70+ years.

Use of the old maintenance facility will continue during the Annex demolition and new facility construction phases, so daily repair / maintenance operations for the Utility are not negatively impacted. The new maintenance facility will be furnished with most of the specially equipment

from the old garage (4 post hoist, welders, band saw, drill press, lockers, plasma cutter etc.) and to limit any operational issues during regular business hours, the transition from the old to new facility will take place over a weekend and will incorporate labour from internal work groups as required.

Once the new maintenance facility has been commissioned and deemed operational, Thunder Bay Hydro will oversee the demolition and removal of the old maintenance facility.

The proposed new maintenance facility attributes include the following aspects;

- Improved safety aspects (shower and eye wash facilities, access/egress doors spaced as per building code requirements, adequately sized vehicle entry doors, additional vehicle entry doors to eliminate manoeuvring vehicles inside the shop)
- Improved ergonomics (flat floor, utilization of the large vehicle hoist would allow the mechanics to stand under the line trucks instead of lying under them), elevated ceiling height with overhead crane, enhanced lighting, ventilation and accessibility, and elevated storage facilities incorporated within the garage.
- Improved industrial hygiene via automatic air exchange devices – Carbon Dioxide sensing that is linked to supply and exhaust air fans, dedicated welding area and dedicated wash bay.
- Fire suppression, annunciation, fire separation walls, and after hour monitoring capabilities.
- Improved environmental aspects (wash bay and the main shop will have a new below ground storage tank to collect run-off water or fluid leaks, and the welding bay would have improved exhaust scrubbing capabilities)
- Improved operational components (separate wash bay, separate welding area, drive-through load out door, small tool repair area, and an oil storage/dispensing area).

The capital spending numbers reported above in Table 2-3.1 exclude all amounts of smart meter spending related to the Smart Meter Project for 2009-2011; however, include the spending required to meet the needs of the Green Energy Act that Thunder Bay Hydro will be seeking in its renewable generation funding adder. These expenses are discussed as part of Thunder Bay Hydro's Green Energy Act Plan and can be found in Exhibit 2, Appendix 2-B and Exhibit 9.

CAPITAL PROJECTS BY YEAR AND USoA

Table 2-3.2 below summarizes Thunder Bay Hydro's investment as per actual work order costs in construction projects for the years 2007 to 2011 (CGAAP) plus projects for the 2012 Bridge Year (CGAAP) and 2013 Test Year (CGAAP and MCGAAP provided). Project descriptions are also provided. Individual projects above the materiality threshold of $85,000 have been listed individually.

Table 2-3.2 - Thunder Bay Hydro's actual work order spending on construction projects for the years 2007 to 2011 (CGAAP)

2007 Distribution Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Actual Work Order costs	Poles, Towers and Fixtures (1830)	Overhead Conductors & Devices (1835)	Overhead Services (1855)	U/G Trenches, Conduit and Vaults (1840)	U/G Conductors and Devices (1845)	U/G Services (1855)	Meter (1860)	Transformer (1850)	Transformer Labour & Materials (1850)	Metering Labour & Materials (1860)	System Supervisory Equip (1980)
1	FRANKWOOD AVE. AREA CONVERSION & REBUILD	$680,800	$247,669	$273,731	$73,203	$1,719	$30,578	$0	$0	$11,340	$42,559	$0	$0
2	TARBUTT STREET AREA REBUILD AND CONVERSION	$495,242	$404,357	$73,514	$5,631	$249	$2,920	$0	$0	$0	$8,572	$0	$0
3	4F5 CONVERSION TO 10M1	$473,335	$12,482	$251,491	$40,195	$55,803	$48,090	$2,885	$0	$3,071	$58,961	$357	$0
4	Joint Use Pole Grey Cr (70 poles)	$170,885	$86,519	$25,310	$4,218	$0	$8,437	$4,218	$0	$21,091	$21,091	$0	$0
5	Hardisty St. Feeder Rebuild	$166,651	$1,533	$91,719	$76,692	$0	-$2,662	$0	$0	-$13,106	$12,475	$0	$0
6	Ridgecrest Rd.- 11 Pole Rebuild	$115,475	$46,694	$50,905	$11,575	$0	$335	$0	$0	$3,372	$2,594	$0	$0
7	HARBOURVIEW TERRACE VAULT IMPROVEMENTS	$93,059	$428	$6,019	$0	$7,768	$78,572	$93	$0	$0	$180	$0	$0
8	MNTCE - 600 Syndicate St. S. - Remove 4kV St	$86,917	$25,099	$54,816	$9,672	$0	$170	$0	$0	-$11,008	$8,167	$0	$0
	Subtotal	$2,282,365	$824,782	$827,505	$221,186	$65,539	$166,440	$7,196	$0	$14,761	$154,600	$357	$0

2007 General Plant Capital Projects
Projects >$85,000 materiality threshold

Ref #	Description		Transportation Equipment (1930)	Computer Equipment Hardware (1920)
9	Vehicle #53-2007 International	$357,294	$357,294	
	Subtotal	$357,294	$357,294	$0

Projects <$85,000	$3,502,821
Cash Contributions & Contributions in Kind	($953,374)
TOTAL CAPITAL 2007	**$5,189,106**

2008 Distribution Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Actual Work Order costs	Poles, Towers and Fixtures (1830)	Overhead Conductors & Devices (1835)	Overhead Services (1855)	U/G Trenches, Conduit and Vaults (1840)	U/G Conductors and Devices (1845)	U/G Services (1855)	Meter (1860)	Transformer (1850)	Transformer Labour & Materials (1850)	Metering Labour & Materials (1860)	System Supervisory Equip (1980)
2	Tarbutt St. Area Conversion/Rebuild	$1,062,486	$117,714	$617,891	$179,966	$211	$0	$214	$0	$72,991	$73,499	$0	$0
10	Hill Street Rebuild	$1,008,692	$442,857	$365,225	$74,462	$157	$25,501	$1,043	$0	$54,652	$44,796	$0	$0
11	Ray Boulevard Rebuild	$595,561	$548,322	$31,090	$0	$0	$0	$35	$0	$16,114	$0	$0	$0
14	WINNIPEG AVE AREA REBUILD	$429,271	$378,070	$36,057	$6,541	$119	$319	$624	$0	$0	$7,541	$0	$0
15	SUMMIT-CORNWALL AREA REBUILD & VOLTAGE CONVERSION	$224,262	$147,776	$59,824	$3,443	$0	$256	$404	$0	$9,470	$3,089	$0	$0
16	County Fair Plaza Line Rebuild	$168,780	$64,450	$29,330	$238	$14,909	$38,307	$2,989	$0	$9,385	$9,171	$0	$0
17	Wayne Toyota - New Pole & U/G cable relocation	$119,323	$34,681	$47,309	$0	$10,386	$23,462	$0	$0	$0	$3,484	$0	$0
18	Belrose Rd. Bridge Rebuild Hydro Pole	$102,217	$43,953	$51,439	$0	$0	$6,352	$474	$0	$0	$0	$0	$0
19	Burwood Rd, pole relocations for Flying J's	$86,714	$50,729	$35,496	$0	$123	$366	$0	$0	$0	$0	$0	$0
	Subtotal	$3,797,306	$1,828,553	$1,273,660	$264,651	$25,906	$94,562	$5,783	$0	$162,612	$141,579	$0	$0

2008 General Plant Capital Projects

Projects >$85,000 materiality threshold

Ref #	Description		Transportation Equipment (1930)	Computer Equipment Hardware (1920)
20	Vehicle #76 2008 F/Liner Cube Van	130,177	130,177	
21	Vehicle #77 2008 Single Bucket	214,704	214,704	
22	i5 Upgrade	114,032		114,032
	Subtotal	458,913	344,881	114,032

Projects <$85,000	$4,127,163
Cash Contributions & Contributions in Kind	($1,425,904)
TOTAL CAPITAL 2008	**$6,957,478**

2009 Distribution Capital Projects - *Projects >$85,000 materiality threshold*

Ref #	Description	Actual Work Order costs	Poles, Towers and Fixtures (1830)	Overhead Conductors & Devices (1835)	Overhead Services (1855)	U/G Trenches, Conduit and Vaults (1840)	U/G Conductors and Devices (1845)	U/G Services (1855)	Meter (1860)	Transformer (1850)	Transformer Labour & Materials (1850)	Metering Labour & Materials (1860)	System Supervisory Equip (1980)
23	ONTARIO BANNING CONVERSION	$1,254,943	$244,037	$253,872	$239,217	$9,728	$33,048	$332,759	$0	$102,307	$39,973	$0	$0
14	WINNIPEG AVE AREA REBUILD	$1,121,306	$181,328	$658,605	$98,334	$10,405	$34,231	$12,869	$0	$95,986	$29,546	$0	$0
24	County Park U/G Cable Trunking	$695,015	$51,672	$30,977	$0	$344,849	$223,010	$712	$0	$4,484	$39,313	$0	$0
15	Summit-Cornwall area rebuild & voltage conversion	$657,884	$240,292	$203,944	$89,781	$74	$6,601	$7,517	$0	$27,222	$82,453	$0	$0
25	10M6 Kam River Crossing	$430,838	$15,655	$30,031	$352	$273,538	$111,232	$28	$0	$0	$0	$0	$0
26	MARY-MOUNTDALE AREA REBUILD	$306,061	$181,271	$123,052	$162	$0	$0	$0	$0	$0	$1,576	$0	$0
27	Mary/Ford Area Conversion/Rebuild	$202,409	$108,885	$76,706	$10,734	$0	$0	$41	$0	$0	$6,043	$0	$0
28	John St. Landfill Co-Generator Connection	$149,950	$149,950	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	2M2 & 2M3 Line Rebuild	$140,290	$96,635	$42,154	$0	$0	$79	$1,422	$0	$0	$0	$0	$0
30	HYDE-MURRAY AREA REBUILD & VOLTAGE CONVERSION	$138,713	$96,071	$5,548	$390	$34,847	$60	$0	$0	$0	$1,797	$0	$0
31	Landfill Gas Utilization Plant - Pole line	$126,830	$45,908	$67,885	$0	$8,870	$0	$0	$0	$0	$4,168	$0	$0
32	Hutton Park Drive Line Extension & Services	$121,468	$33,827	$37,487	$413	$19,701	$13,021	$7,912	$0	$0	$9,108	$0	$0
33	VERADALE ST. BETWEEN 25TH SD RD & GORDONVALE	$92,329	$29,612	$32,791	$11,614	$97	$7,446	$3,221	$0	$7,093	$455	$0	$0
	Subtotal	$5,438,037	$1,475,143	$1,563,052	$450,998	$702,110	$428,727	$366,483	$0	$237,092	$214,432	$0	$0

2009 General Plant Capital Projects

Projects >$85,000 materiality threshold

Ref #	Description		Transportation Equipment (1930)	Computer Equipment Hardware (1920)
34	Vehicle #54 2009 Derrick Digger	250,245	250,245	
35	Vehicle#87 2009 Single Bucket	207,372	207,372	
	Subtotal	457,617	457,617	-

Projects <$85,000	$2,961,432
Cash Contributions & Contributions in Kind	($1,188,775)
TOTAL CAPITAL 2009	**$7,668,310**

2010 Distribution Capital Projects - *Projects >$85,000 materiality threshold*

Ref #	Description	Actual Work Order costs	Poles, Towers and Fixtures (1830)	Overhead Conductors & Devices (1835)	Overhead Services (1855)	U/G Trenches, Conduit and Vaults (1840)	U/G Conductors and Devices (1845)	U/G Services (1855)	Meter (1860)	Transformer (1850)	Transformer Labour & Materials (1850)	Metering Labour & Materials (1860)	System Supervisory Equip (1980)
30	HYDE-MURRAY AREA REBUILD & VOLTAGE CONVERSION	$1,067,482	$313,941	$405,723	$186,542	$13,164	$26,261	$2,575	$0	$69,792	$49,484	$0	$0
36	Lily-Donald Area Conversion/Rebuild	$940,595	$298,032	$489,044	$52,372	$14,966	$18,569	$154	$0	$45,651	$21,806	$0	$0
37	County Fair Park U/G Line Rebuild-Phase 2	$675,097	$21,825	$12,061	$0	$208,833	$127,860	$11,680	$0	$78,287	$214,550	$0	$0
38	CENTRE-FRANCIS AREA REBUILD	$616,840	$451,145	$113,310	$0	$0	$0	$0	$0	$52,097	$288	$0	$0
26	MARY-MOUNTDALE AREA REBUILD	$353,765	$31,387	$175,098	$56,449	$0	$7,083	$439	$0	$20,686	$62,622	$0	$0
28	John St. Landfill Co-Generator Connection	$269,791	$242,935	$230	$0	$371	$0	$34	$0	$0	$1,142	$735	$0
27	Mary/Ford Area Conversion/Rebuild	$253,999	$57,242	$61,199	$77,666	$0	$10,456	$0	$0	$30,281	$17,154	$0	$0
39	Miles Street between Archibald and Brodie - Relocations	$190,980	$9,418	$1,949	$0	$48,494	$110,156	$456	$0	$0	$20,507	$0	$0
40	Arthur Street between May and Brodie Street - Relocations	$188,058	$11,717	$13,189	$0	$4,964	$122,231	$439	$0	$3,922	$31,595	$0	$0
41	Phase 2 - 2M2/2M3 Line Rebuild	$173,033	$117,523	$55,511	$0	$0	$0	$0	$0	-$1	$0	$0	$0
42	SKYPOWER 7MW AIRPORT SOLAR PROJECT	$172,601	$172,601	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
43	SKYPOWER 8.9MW FORT WILLIAM FIRST NATION SOLAR PROJECT	$172,499	$172,499	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
44	MONTREAL-MOUNTDALE AREA REBUILD	$149,495	$140,827	$8,669	$0	$0	$0	$0	$0	$0	$0	$0	$0
45	Brock Syndicate Area Conversion/Rebuild	$117,544	$112,412	$5,132	$0	$0	$0	$0	$0	$0	$0	$0	$0
46	777 Memorial Ave - Walmart	$97,874	$7,104	$48	$678	$55,469	$202	$1,358	$21,382	$7,967	$3,666	$0	$0
47	BROWN-ISABELLA AREA CONVERSION REBUILD	$85,158	$85,158	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	$5,524,812	$2,245,765	$1,341,164	$373,708	$346,262	$422,820	$17,136	$21,382	$308,683	$422,814	$735	$0

2010 General Plant Capital Projects

Projects >$85,000 materiality threshold

Ref #	Description		Transportation Equipment (1930)	Computer Equipment Hardware (1920)
48	Vehicle #60 2010 Double Bucket	$358,991	$358,991	
49	Vehicle #61 2010 Double Bucket	$337,205	$337,205	
50	Vehicle #97 2010 Single Bucket	$101,811	$101,811	
	Subtotal	$798,007	$798,007	$0

Projects <$85,000	$3,754,022
Cash Contributions & Contributions in Kind	($2,499,649)
TOTAL CAPITAL 2010	**$7,577,192**

2011 Distribution Capital Projects - *Projects >$85,000 materiality threshold*

Ref #	Description	Actual Work Order costs	Poles, Towers and Fixtures (1830)	Overhead Conductors & Devices (1835)	Overhead Services (1855)	U/G Trenches, Conduit and Vaults (1840)	U/G Conductors and Devices (1845)	U/G Services (1855)	Meter (1860)	Transformer (1850)	Transformer Labour & Materials (1850)	Metering Labour & Materials (1860)	System Supervisory Equip (1980)
38	CENTRE-FRANCIS AREA REBUILD	$1,284,820	$163,470	$776,714	$135,443	$16,803	$15,566	$664	$0	$16,727	$159,433	$0	$0
45	Brock Syndicate Area Conversion/Rebuild	$1,284,459	$310,712	$629,219	$167,024	$16,721	$23,845	$5,147	$0	$68,137	$63,654	$0	$0
47	BROWN-ISABELLA AREA CONVERSION REBUILD	$927,305	$765,673	$115,873	$474	$8,548	$20,797	$5,948	$0	$7,424	$2,568	$0	$0
51	Brock-Ford Area Rebuild	$796,268	$642,130	$104,622	$13,353	$0	$802	$809	$0	$4,778	$29,774	$0	$0
52	College Park U/G Rebuild Phase 1	$687,439	$36,799	$12,242	$187	$293,689	$205,944	$453	$0	$41,841	$96,284	$0	$0
44	MONTREAL-MOUNTDALE AREA REBUILD	$547,092	$129,611	$254,219	$70,400	$0	$16,489	$264	$0	$43,278	$32,831	$0	$0
53	Golf Links Road Widening	$423,338	$330,372	$81,405	$4,758	$0	$0	$0	$0	$1,272	$5,531	$0	$0
54	Prince Arthur's Landing	$297,421	$24,274	$47,612	$0	$0	$91,769	$202	$0	$86,094	$47,469	$0	$0
42	SKYPOWER 7MW AIRPORT SOLAR PROJECT	$290,762	$40,278	$3,406	$1,507	$110,733	$113,467	$187	$0	$0	$21,183	$0	$0
55	Hwy 11-17 @ Balsam - Pole Relocations	$254,205	$118,246	$128,968	$0	$0	$326	$0	$0	$5,156	$1,510	$0	$0
56	HWY 11-17 @ HODDER, POLE RELOCATIONS	$207,429	$90,262	$93,939	$82	$931	$18,513	$0	$0	$301	$3,401	$0	$0
57	P.A. Landing Development - New cable to V1	$104,800	$1,716	$0	$0	$332	$79,959	$134	$0	$0	$22,659	$0	$0
58	Fort William TS Feeder Cable Replacement	$104,744	$1,097	$10,418	$0	$0	$92,875	$0	$0	$0	$354	$0	$0
59	Mayflower Drive & Sunflower Street Conversion	$102,436	$481	$200	$0	$20,388	$60,158	$673	$0	$0	$20,536	$0	$0
	Subtotal	$7,312,517	$2,655,121	$2,258,837	$393,228	$468,145	$740,511	$14,482	$0	$275,007	$507,187	$0	$0

2011 General Plant Capital Projects
Projects >$85,000 materiality threshold

Ref #	Description		Transportation Equipment (1930)	Computer Equipment Hardware (1920)
60	Vehicle #942 Backhoe/Loader	$132,159	$132,159	
61	Vehicle #82 2012 Altec	$139,681	$139,681	
	Subtotal	$271,840	$271,840	$0

Projects <$85,000	$3,606,211
Cash Contributions & Contributions in Kind	($2,958,053)
TOTAL CAPITAL 2011	**$8,232,515**

2012 Distribution Capital Projects *- Projects >$85,000 materiality threshold*

Ref #	Description	Actual Work Order costs	Poles, Towers and Fixtures (1830)	Overhead Conductors & Devices (1835)	Overhead Services (1855)	U/G Trenches, Conduit and Vaults (1840)	U/G Conductors and Devices (1845)	U/G Services (1855)	Meter (1860)	Transformer (1850)	Transformer Labour & Materials (1850)	Metering Labour & Materials (1860)	System Supervisory Equip (1980)
51	Brock-Ford Area Rebuild	$1,440,500	$215,120	$921,264	$59,324	$52	$37,394	$3,925	$0	$101,701	$101,701	$20	$0
47	BROWN-ISABELLA AREA CONVERSION REBUILD	$1,616,456	$391,611	$959,359	$86,024	$16,108	$17,708	$40	$0	$72,803	$72,803	$0	$0
62	OGDEN-MCMURRAY AREA CONVERSION REBUILD	$817,776	$811,110	$6,666	$0	$0	$0	$0	$0	$0	$0	$0	$0
63	GEORGINA-FRANCIS AREA REBUILD	$1,096,922	$384,714	$465,860	$103,652	$20,337	$22,501	$3,000	$0	$48,429	$48,429	$0	$0
44	MONTREAL-MOUNTDALE AREA REBUILD	$86,907	$39,618	$45,473	$2,827	$0	-$652	$0	$0	$0	-$358	$0	$0
64	Partial Discharge Cable Testing	$206,061	$16,105	$25,047	$0	$25,200	$138,280	$0	$0	$0	$1,428	$0	$0
65	Golf Links Road Widening	$321,846	$144,895	$175,154	$0	$0	$0	$0	$0	$1,338	$459	$0	$0
58	Fort William TS Feeder Cable Replacement	$225,602	$3,127	$608	$0	$0	$221,866					$0	$0
66	New Courthouse - Miles @ Brodie	$183,079	$5,359	$0	$0	$125,336	$28,730	$17,835	$0	$0	$5,820	$0	$0
43	SKYPOWER 8.9MW FORT WILLIAM FIRST NATION SOLAR PROJECT	$148,680	$126,058	$20,900	$0	$0	$0	$0	$757	$0	$964	$0	$0
42	SKYPOWER 7MW AIRPORT SOLAR PROJECT	$87,007	$87,007	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
80	GEA Plan - Reclosers	$207,587	$19,690	$6,839	$788	$22,942	$66,016	$66,419	$5,204	$0	$0	$19,690	$0
	Subtotal	$6,438,424	$2,244,415	$2,627,170	$252,615	$209,975	$531,843	$91,219	$5,961	$224,271	$231,246	$19,710	$0

2012 General Plant Capital Projects
Projects >$85,000 materiality threshold

Ref #	Description		Transportation Equipment (1930)	Computer Equipment Hardware (1920)
67	Single Bucket Truck	$120,000	$120,000	
68	i5 Upgrade	$117,269		$117,269
	Subtotal	$237,269	$120,000	$117,269

Projects <$85,000	$4,183,847
Cash Contributions & Contributions in Kind	($2,022,925)
TOTAL CAPITAL 2012	**$8,836,615**

2013 Distribution Capital Projects (CGAAP) - *Projects >$85,000 materiality threshold*

Ref #	Description	Actual Work Order costs	Poles, Towers and Fixtures (1830)	Overhead Conductors & Devices (1835)	Overhead Services (1855)	U/G Trenches, Conduit and Vaults (1840)	U/G Conductors and Devices (1845)	U/G Services (1855)	Meter (1860)	Transformer (1850)	Transformer Labour & Materials (1850)	Metering Labour & Materials (1860)	System Supervisory Equip (1980)
69	Durban/Brodie Rebuild	$803,690	$272,137	$345,664	$80,387	$16,077	$16,077	$0	$0	$36,674	$36,674	$0	$0
70	Mary/Heath	$1,374,197	$467,058	$591,014	$137,445	$27,489	$27,489	$0	$0	$61,851	$61,851	$0	$0
62	Ogden/McMurray Rebuild	$1,720,804	$240,427	$1,118,890	$137,710	$34,427	$34,427	$0	$0	$77,462	$77,462	$0	$0
71	Brunswick/Legion	$724,103	$246,127	$311,409	$72,421	$14,484	$14,484	$0	$0	$32,590	$32,590	$0	$0
72	Huron/Otto - Pole Set only	$518,466	$414,777	$103,689	$0	$0	$0	$0	$0	$0	$0	$0	$0
73	Elliott/Leslie	$960,257	$326,306	$413,029	$96,053	$19,211	$19,211	$0	$0	$43,224	$43,224	$0	$0
74	10M3 to 17M1 Connection @ Main St	$141,123	$14,116	$56,448	$0	$14,112	$11,290	$0	$0	$22,579	$22,579	$0	$0
75	Black Bay/Dewe - Design Contract	$89,342	$89,342	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
80	GEA Plan - Reclosers	$187,893	$41,336	$144,678	$0	$0	$0	$0	$0	$0	$0	$0	$1,879
	Subtotal	$6,519,875	$2,111,626	$3,084,820	$524,016	$125,800	$122,978	$0	$0	$274,379	$274,379	$0	$1,879

2013 General Plant Capital Projects
Projects >$85,000 materiality threshold

Ref #	Description	Actual $	Transportation Equipment (1930)	Computer Equipment Hardware (1920)	Buildings (1808)
76	RBD Truck	$220,345	$220,345		
77	Single Bucket Truck	$230,000	$230,000		
78	Double Bucket Truck	$375,000	$375,000		
79	Garage	$3,303,500			$3,303,500
	Subtotal	$4,128,845	$825,345	$0	$3,303,500

Projects <$85,000	$3,785,748
Cash Contributions & Contributions in Kind	($1,044,834)
TOTAL CAPITAL 2013	**$13,389,634**

2013 Distribution Capital Projects (MCGAAP) - *Projects >$85,000 materiality threshold*

Ref #	Description	Actual Work Order costs	Poles, Towers and Fixtures (1830)	Overhead Conductors & Devices (1835)	Overhead Services (1855)	U/G Trenches, Conduit and Vaults (1840)	U/G Conductors and Devices (1845)	U/G Services (1855)	Meter (1860)	Transformer (1850)	Transformer Labour & Materials (1850)	Metering Labour & Materials (1860)	System Supervisory Equip (1980)
69	Durban/Brodie Rebuild	$803,871	$273,316	$345,664	$80,387	$16,077	$16,077	$0	$0	$36,174	$36,174	$0	$0
70	Mary/Heath	$1,374,452	$467,314	$591,014	$137,445	$27,489	$27,489	$0	$0	$61,851	$61,851	$0	$0
62	Ogden/McMurray Rebuild	$1,721,369	$240,992	$1,118,890	$137,710	$34,427	$34,427	$0	$0	$77,462	$77,462	$0	$0
71	Brunswick/Legion	$724,206	$246,230	$311,409	$72,421	$14,484	$14,484	$0	$0	$32,590	$32,590	$0	$0
72	Huron/Otto - Pole Set only	$518,443	$414,755	$103,689	$0	$0	$0	$0	$0	$0	$0	$0	$0
73	Elliott/Leslie	$960,532	$326,581	$413,029	$96,053	$19,211	$19,211	$0	$0	$43,224	$43,224	$0	$0
74	10M3 to 17M1 Connection @ Main St	$141,119	$14,112	$56,448	$0	$14,112	$11,290	$0	$0	$22,579	$22,579	$0	$0
75	Black Bay/Dewe - Design Contract	$89,342	$89,342	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
80	GEA Plan - Reclosers	$187,893	$41,336	$144,678	$0	$0	$0	$0	$0	$0	$0	$0	$1,879
	Subtotal	$6,521,227	$2,113,977	$3,084,821	$524,016	$125,801	$122,978	$0	$0	$273,879	$273,879	$0	$1,879

2013 General Plant Capital Projects
Projects >$85,000 materiality threshold

Ref #	Description	Actual $	Transportation Equipment (1930)	Computer Equipment Hardware (1920)	Buildings (1808)
76	RBD Truck	$220,345	$220,345		
77	Single Bucket Truck	$230,000	$230,000		
78	Double Bucket Truck	$375,000	$375,000		
79	Garage	$3,303,500			$3,303,500
	Subtotal	$4,128,845	$825,345	$0	$3,303,500

Projects <$85,000	$2,472,105
Cash Contributions & Contributions in Kind	($989,985)
TOTAL CAPITAL 2013	**$12,132,192**

DISTRIBUTION PLANT AND GENERAL PROJECTS

For the projects listed above that exceed the $85,000 materiality threshold, additional detail is provided in Table 2-3.3 below (2007 to 2012 CGAAP and 2013 MCGAAP). Please note that no project requires Leave to Construct approval under Section 92 of the OEB Act or has a project life cycle greater than one year. Thunder Bay Hydro defines its projects by geographical area; however, specific capital projects within the grander project are less than a year in scope.

Also, the cost/benefit analysis has been noted as N/A for all projects as each project was either customer driven or required for maintenance/end of life purposes.

Please note the reference numbers in Table 2-3.2 are to refer to the same project in Table 2-3.3 for cross-reference purposes.

Table 2-3.3 -Projects that exceed the $85,000 materiality threshold

2007 Distribution Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
1	FRANKWOOD AVE. AREA CONVERSION & REBUILD	Rebuild Poles, Transfer Load	Associated Substation at end of life, poles at end of life	Rebuild 100 Poles and lines	Aug-06	Jan-08	N/A	N/A	$680,800
2	TARBUTT STREET AREA REBUILD AND CONVERSION	Rebuild Poles, Convert Voltage	Poles at end of life	Rebuild 156 Poles and lines	Oct-07	Jan-08	N/A	N/A	$495,242
3	4F5 CONVERSION TO 10M1	Convert 4kV to 25 kV	Associated Substation at end of life, poles at end of life	Rebuild 26 poles, 5 pads and lines	May-06	May-07	N/A	N/A	$473,335
4	Joint Use Pole Grey Cr	Convert 4kV to 25 kV	Associated Substation at end of life, poles at end of life	Rebuild 70 poles and lines	Feb-06	Mar-07	N/A	N/A	$170,885
5	Hardisty St. Feeder Rebuild	Convert 4kV to 25 kV	Associated Substation at end of life, poles at end of life	Rebuild 58 poles and lines	Oct-05	May-07	N/A	N/A	$166,651
6	Ridgecrest Rd.- 11 Pole Rebuild	Rebuild Poles	Poles at end of life	Rebuild 11 poles and lines	May-07	Dec-07	N/A	N/A	$115,475
7	HARBOURVIEW TERRACE VAULT IMPROVEMENTS	Upgrade system functionality	Convert radial to loop feed, swiching capabilities required	Replace fusing and switching in vault	Sep-07	Mar-08	N/A	N/A	$93,059
8	MNTCE - 600 Syndicate St. S. - Remove 4kV St	Install new poles, relocated service	Transformer Bank at end of life	Install 3 new poles, relocated service	Jul-07	Jan-08	N/A	N/A	$86,917
	Subtotal								$2,282,365

2007 General Plant Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
9	Vehicle #53-2007	A new vehicle provides updated safety, labour and environmental improvements such as improved suspension, new seats, LED lighting, additional internal storage as well as increased reliability, increased fuel economy, reduced emissions, new vehicle warranty and improved appearance (no rust or body panel holes).	This project would see Truck #44 (a double bucket truck on a 1987 GMC) replaced with a newer unit	2007 Double Bucket	Jun -07	Jun -07	N/A	N/A	$357,294
	Subtotal								$357,294
	Projects <$85,000								$3,502,821
	Cash Contributions & Contributions in Kind								($953,374)
	TOTAL CAPITAL 2007								**$5,189,106**

2008 Distribution Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
2	Tarbutt St. Area Conversion	Rebuild Poles, Convert Voltage	Poles at end of life	Rebuild 156 Poles	Jan-08	Oct-10	N/A	N/A	$1,062,486
10	Hill Street Rebuild	Rebuild Poles, Convert Voltage	Associated Substation at end of life, poles at end of life	Rebuild 100 poles	Aug-08	Feb-09	N/A	N/A	$1,008,692
11	Ray Boulevard Rebuild	Rebuild Poles, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 150 poles	Jan-08	Dec-12	N/A	N/A	$595,561
14	WINNIPEG AVE AREA REBUILD	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 150 poles, 3 pads	Oct-08	Jul-09	N/A	N/A	$429,271
15	SUMMIT-CORNWALL AREA REBUILD & VOLTAGE CONVERSION	Rebuild Area, Convert Voltage	Substation at end of life	Rebuild 40 poles	Nov-08	Nov-09	N/A	N/A	$224,262
16	County Fair Plaza Line Rebuild	Rebuild Poles	Poles at end of life	Rebuild 9 poles	Apr-08	Aug-08	N/A	N/A	$168,780
17	Wayne Toyota - New Pole & U/G cable relocation	Relocated service, new pole	New building addition	New pole, relocate service	Aug-08	Oct-08	N/A	N/A	$119,323
18	Belrose Rd. Bridge Rebuildment Hydro Pole	Relocate pole, new pole	City driven- bridge replacement	New pole, relocate existing pole	May-08	Jul-08	N/A	N/A	$102,217
19	Burwood Rd, pole relocations for Flying J's	Relocate poles	Road Widening	Relocate poles	Aug-08	Nov-08	N/A	N/A	$86,714
	Subtotal								$3,797,306

2008 General Plant Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
20	Vehicle #76 2008 F/Liner Cube Van	A new vehicle provides updated safety, labour and environmental improvements such as improved suspension, new seats, LED lighting, additional internal storage as well as increased reliability, increased fuel economy, reduced emissions, new vehicle warranty and improved appearance (no rust or body panel holes).	Truck #46 (an underground truck) replaced with a newer unit.	Purchase of F/Liner Cube Van	Dec 08	Jan 09	N/A	N/A	$130,177
21	Vehicle #77 2008 Single Bucket	A new vehicle provides updated safety, labour and environmental improvements such as improved suspension, new seats, LED lighting, additional internal storage as well as increased reliability, increased fuel economy, reduced emissions, new vehicle warranty and improved appearance (no rust or body panel holes).	Truck #47 (a single bucket truck) replaced with a newer unit.	Purchase a single bucket truck.	Sep-08	Oct-08	N/A	N/A	$214,704
22	i5 Upgrade	Provides additional core functionality for corporate ERP computer system, replaces out of warranty, end of life corporate ERP computer system, and renews O/S related software maintenance agreements on corporate ERP computer system.	The upgrade is needed as computer system at end of life, increase data storage, memory and processor capabilities to address additional corporate computing requirements, and enhance system responsiveness for core line of business computer applications	Replacement or upgrade of all computer hardware for corporate ERP system, renew hardware and software maintenance agreements for new system, configure new system to support existing corporate requirements, reload all O/S and line of business software, and migration of corporate line of business data from old system to new	Dec-07	Jan-08	N/A	N/A	$114,032
	Subtotal								$458,913
	Projects <$85,000								$4,127,163
	Cash Contributions & Contributions in Kind								($1,425,904)
	TOTAL CAPITAL 2008								**$6,957,478**

2009 Distribution Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
23	ONTARIO BANNING CONVERSION	Rebuild Poles, Convert Voltage	Associated Substation at end of life, poles at end of life	Rebuild 42 poles	Dec-08	Sep-09	N/A	N/A	$1,254,943
14	WINNIPEG AVE AREA REBUILD	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 150 poles, 3 pads	Oct-08	Jul-09	N/A	N/A	$1,121,306
24	County Park U/G Cable Trunking	Rebuild Underground Feed	Underground loop old and fragile, transformers end of life	Install 2km U/G new express feed, PMH	Apr-09	Oct-09	N/A	N/A	$695,015
15	SUMMIT-CORNWALL AREA REBUILD & VOLTAGE CONVErsion	Rebuild Area, Convert Voltage	Substation at end of life	Rebuild 40 poles	Nov-08	Nov-09	N/A	N/A	$657,884
25	10M6 Kam River Crossing	Install new cable	Tunnel where cable strung being abandoned	Intall 2 new poles, pull new 3ph	Feb-09	Mar-09	N/A	N/A	$430,838
26	MARY-MOUNTDALE AREA REBUILD	Rebuild Area, Convert Voltage	Poles at end of life, restricted conductor	Rebuild 65 poles, 2 pads	Sep-09	Sep-10	N/A	N/A	$306,061
27	Mary/Ford Area Conversion/Rebuild	Rebuild Area, Transfer Load	Poles at end of life, restricted conductor, overleaded circuit	Rebuild 51 poles, 2 pads	Aug-09	Mar-10	N/A	N/A	$202,409
28	John St. Landfill Co-Generator Connection	Protection Upgrades	Communication upgrade between Mapleward and Landfill	Generator Connection	Jun-10	Jul-10	500 kW	N/A	$149,950
29	2M2 & 2M3 Line Rebuild	Rebuild Poles	Poles end of life from risk assessment	Rebuild 101 Poles	Dec-09	Dec-09	N/A	N/A	$140,290
30	HYDE-MURRAY AREA REBUILD & VOLTAGE CONVERSION	Rebuild Area, Convert Voltage	Poles at end of life, restricted conductor	Rebuild 115 poles	Dec-08	Feb-11	N/A	N/A	$138,713
31	Landfill Gas Utilization Plant - Pole line	Rebuild pole line and switch	New three phase line for landfill	Install 10 new poles, and 3 phase line	Jan-10	Aug-10	N/A	N/A	$126,830
32	Hutton Park Drive Line Extension & Services	Build new pole line	Pole line extension, transformers to feed 25 new lots	Install 11 new poles and line for new customers	Nov-09	Dec-09	N/A	N/A	$121,468
33	VERADALE ST. BETWEEN 25TH SD RD & GORDONVALE	Rebuild Area	Poles end of life and needing relocation to hydro easement	Rebuild 15 poles and lines	Jun-09	Sep-09	N/A	N/A	$92,329
	Subtotal								$5,438,037

2009 General Plant Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
34	Vehicle #54 2009 Derrick Digger	This truck was to assist in the completion of the 2008 Capital and maintenance budgets, reduce down time, and truck maintenance costs. A new truck brings with it better safety features such as lighting.	Lines was short I RBD as the existing truck 14 had to be permanently taken off the road due to safety issues. Crews are having to be sent to return to job sites in order to complete the work.	Replacement of truck #14 which has a 1987 chasis and a 1971 boom with a new 47 foot reach RBD	Jun-07	Aug-09	N/A	N/A	$250,245
35	Vehicle#87 2009 Single Bucket	Improved reliability and fuel consumption. The new unit will have more set up options to improve positioning and ergonomics.	To increase efficiency the utility will be able to send a single bucket rather than a double bucket to change over services or keep a 2 man crew working on capital projects. The truck will also allow lines to have an alternate truck for use when the service or stand-by trucks go down.	This is to replace truck #47 which is a 1974 single bucket truck	Jun -08	Jun -09	N/A	N/A	$207,372
	Subtotal								$457,617
	Projects <$85,000								$2,961,432
	Cash Contributions & Contributions in Kind								($1,188,775)
	TOTAL CAPITAL 2009								**$7,668,310**

1

2010 Distribution Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
30	HYDE-MURRAY AREA REBUILD & VOLTAGE CONVERSION	Rebuild Area, Convert Voltage	Poles at end of life, restricted conductor	Rebuild 115 poles	Dec-08	Feb-11	N/A	N/A	$1,067,482
36	Lily-Donald Area Conversion/Rebuild	Transfer Load, Rebuild area	Conductors, poles, substation at end of life	Rebuild 110 poles	Mar-10	Oct-10	N/A	N/A	$940,595
37	County Fair Park U/G Line Rebuild-Phase 2	Replace U/G feed, rebuild area	U/G Conductors and transformers at end of life	Rebuild new 1.4k feed, 18 pads	Jun-10	Nov-10	N/A	N/A	$675,097
38	CENTRE-FRANCIS AREA REBUILD	Transfer Load, Rebuild area	Poles, substation at end of life, restricted conductor	Rebuild 158 poles, 7 pads	Oct-10	Mar-12	N/A	N/A	$616,840
26	MARY-MOUNTDALE AREA REBUILD	Rebuild Area, Convert Voltage	Poles at end of life, restricted conductor	Rebuild 65 poles, 2 pads	Sep-09	Sep-10	N/A	N/A	$353,765
28	John St. Landfill Co-Generator Connection	Protection Upgrades	Communication upgrade between Mapleward and Landfill	Generator Connection	Jun-10	Jul-10	500 kW	N/A	$269,791
27	Mary/Ford Area Conversion/Rebuild	Rebuild Area, Transfer Load	Poles at end of life, restricted conductor, overleaded circuit	Rebuild 51 poles, 2 pads	Aug-09	Mar-10	N/A	N/A	$253,999
39	Miles Street between Archibald and Brodie - Relocations	Relocated U/G cables and pad	City driven relocation	Relocate 3 ph pad and cables	Mar-10	Oct-10	N/A	N/A	$190,980
40	Arthur Street between May and Brodie Street - Relocations	Rebuild to U/G	City driven Replacement	Remove 3ph pole line to U/G cables	Sep-10	Oct-10	N/A	N/A	$188,058
41	Phase 2 - 2M2/2M3 Line Rebuild	Rebuild Area	Poles end of life (ant infestation)	Rebuild 15 poles and lines	Jun-10	Aug-10	N/A	N/A	$173,033
42	SKYPOWER 7MW AIRPORT SOLAR PROJECT	System Upgrades for connection	New solar at airport requires protection enhancements	Generator Connection	Mar-11	Aug-11	500 kW	N/A	$172,601
43	SKYPOWER 8.9MW FORT WILLIAM FIRST NATION SOLAR PROJECT	System Upgrades for connection	New solar FWFN requires protection enhancements	Generator Connection	Apr-10	Mar-12	500 kW	N/A	$172,499
44	MONTREAL-MOUNTDALE AREA REBUILD	Rebuild Area, Convert Voltage, Transfer Load	Poles at end of life, restricted conductor	Rebuild 70 poles	Nov-11	May-12	N/A	N/A	$149,495
45	Brock Syndicate Area Conversion/Rebuild	Rebuild Area, Convert Voltage	Poles at end of life, restricted conductor	Rebuild 119 poles, 6 pads	Aug-10	Dec-11	N/A	N/A	$117,544
46	777 Memorial Ave - Walmart	Upgrade service	Increase service size	Upgrade service from 1000 - 1600 A	Nov-10	Nov-10	300 kW	N/A	$97,874
47	BROWN-ISABELLA AREA CONVERSION REBUILD	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Set 220 Poles	Oct-10	Ongoing	N/A	N/A	$85,158
	Subtotal								$5,524,812

2010 General Plant Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
48	Vehicle #60 2010 Double Bucket	Due to the increase in staff levels in the Lines Department, additional vehicles for live-line work are required.	Improves the reliability, fuel consumption, and completion of capital /maintenance projects.	Purchase of a new 55' double bucket, material handler	June - 08	Mar-10	N/A	N/A	$358,991
49	Vehicle #61 2010 Double Bucket	Due to the increase in staff levels in the Lines Department, additional vehicles for live-line work are required.	Improves the reliability, fuel consumption, and completion of capital /maintenance projects.	Purchase of a new 55' double bucket material handler	Jul-09	Jan-11	N/A	N/A	$337,205
50	Vehicle #97 2010 Single Bucket	Improved Fuel consumption. To preform service work on capital projects. The truck matches the type of work being preformed and more services could be converted in a day.	Keeps costs down as the truck is designed for the work. The truck fits into smaller areas such as lanes.	Purchase new 38 foot fully articulating single bucket truck	Jun-09	Jul-10	N/A	N/A	$101,811
	Subtotal								$798,007
	Projects <$85,000								$3,754,022
	Cash Contributions & Contributions in Kind								($2,499,649)
	TOTAL CAPITAL 2010								**$7,577,192**

1

2011 Distribution Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
38	CENTRE-FRANCIS AREA REBUILD Brock Syndicate Area	Transfer Load, Rebuild area	Poles, substation at end of life, restricted conductor	Rebuild 158 poles, 7 pads	Oct-10	Mar-12	N/A	N/A	$1,284,820
45	Conversion/Rebuild BROWN-ISABELLA AREA	Rebuild Area, Convert Voltage	Poles at end of life, restricted conductor	Rebuild 119 poles, 6 pads	Aug-10	Dec-11	N/A	N/A	$1,284,459
47	CONVERSION REBUILD	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Set 220 Poles	Oct-10	Ongoing	N/A	N/A	$927,305
51	Brock-Ford Area Rebuild	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Set 147 poles	Jun-11	Ongoing	N/A	N/A	$796,268
52	College Park U/G Rebuild Phase 1 MONTREAL-MOUNTDALE AREA	Rebuild Area	U/G Conductors and transformers at end of life	Rebuild 1.4k U/G cable, 2 PMH	May-11	Dec-11	N/A	N/A	$687,439
44	REBUILD	Rebuild Area, Convert Voltage, Transfer Load	Poles at end of life, restricted conductor	Rebuild 70 poles	Nov-11	May-12	N/A	N/A	$547,092
53	Golf Links Road Widening	Pole line relocation	Road Widening	Rebuild 56 poles and lines	Aug-11	Ongoing	N/A	N/A	$423,338
54	Prince Arthur's Landing	Review, Inspect, approve subdivision	New subdivision at prince arthur landing	Install 4 new poles, 2 PMH, 6 pads	Feb-11	Nov-11	500 kW	N/A	$297,421
42	SKYPOWER 7MW AIRPORT SOLAR PROJECT	System Upgrades for connection	New solar at airport requires protection enhancements	Generator Connection	Mar-11	Aug-11	500 kW	N/A	$290,762
55	Hwy 11-17 @ Balsam - Pole Relocations	Pole line relocation	MTO new road ramps	Rebuild 11 poles and line	Apr-11	May-11	N/A	N/A	$254,205
56	HWY 11-17 @ HODDER, POLE RELOCATIONS	Pole line relocation	Road Widening	Rebuild 15 poles and line	Jun-11	Nov-11	N/A	N/A	$207,429
57	P.A. Landing Development - New cable to V1	Rebuild to U/G	Waterfront Project	Remove 2 poles replace with UG cable	Oct-11	Mar-12	N/A	N/A	$104,800
58	Fort William TS Feeder Cable Replacement	Replace U/G feeder	Test results indicated imminent failure	One feeder and termination replacement	May-11	Jul-12	N/A	N/A	$104,744
59	Mayflower Drive & Sunflower Street Conversion	Rebuild Area, Convert Voltage	12 kV load to be transferred to 25kV	Rebuild 200m U/G cable, and dip poles	Dec-09	Jun-11	N/A	N/A	$102,436
	Subtotal								$7,312,517

2011 General Plant Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
60	Vehicle #942 Backhoe/Loader	A new loader provides updated safety, ergonomic, and environmental imprrovements, such as doors on both sides of the machine, multi-position dropdown rear window, new seat, ergonomically shaped/minimum movement controls. It would provide a closed loop hydraulic system, improved reliability, and increased fuel economy.	Backhoe loader #911 has over 7,800 hours on it, for which the manufactuer recommends a complete machine overhaul and rebuild (cost 70K).	Purchase a new multi-purpose backhoe loader with 4 in 1 bucket, conventional bucket, pallet forks, and snow plow blade to replace backhoe #911 (1997)	Jul-10	Jul-11	N/A	N/A	$132,159
61	Vehicle #82 2012 Altec	Required to complete work	Unit has been rented since June 2011 and the utility continues to need it to complete the work.	Purchase Altec	Sep-11	Nov-11	N/A	N/A	$139,681
	Subtotal								$271,840
	Projects <$85,000								$3,606,211
	Cash Contributions & Contributions in Kind								($2,958,053)
	TOTAL CAPITAL 2011								**$8,232,515**

1

2012 Distribution Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
51	Brock-Ford Area Rebuild	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 147 poles, 9 pads	Jun-11	Sep-12	N/A	N/A	$ 1,440,500
47	BROWN-ISABELLA AREA CONVERSION REBUILD	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 220 poles, 6 pads	Oct-10	Ongoing	N/A	N/A	$ 1,616,456
62	OGDEN-MCMURRAY AREA CONVERSION REBUILD	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 213 poles, 6 pads	Apr-12	Ongoing	N/A	N/A	$ 817,776
63	GEORGINA-FRANCIS AREA REBUILD	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 65 poles and 3 pads	Aug-12	Ongoing	N/A	N/A	$ 1,096,922
44	MONTREAL-MOUNTDALE AREA REBUILD	Rebuild Area, Convert Voltage, Transfer Load	Poles at end of life, restricted conductor	Rebuild 70 poles	Nov-11	May-12	N/A	N/A	$ 86,907
64	Partial Discharge Cable Testing	Test Cables to create a replacement plan	Cables reaching end of life, knowledge required for maintanence	18 cables tested	Apr-12	Jul-12	N/A	N/A	$ 206,061
65	Golf Links Road Widening	Pole line relocation	Road Widening	Rebuild 56 poles and lines	Aug-11	Ongoing	N/A	N/A	$ 321,846
58	Fort William TS Feeder Cable Replacement	Replace U/G feeder	Test results indicated imminent failure	One feeder and termination replacement	May-11	Jul-12	N/A	N/A	$ 225,602
66	New Courthouse - Miles @ Brodie	System upgrade for multiple feeds	Risk mitigation for damage and reliability	Rebuild Infastructure to vault	Mar-12	Ongoing	N/A	N/A	$ 183,079
43	SKYPOWER 8.9MW FORT WILLIAM FIRST NATION SOLAR PROJECT	System Upgrades for connection	New solar FWFN requires protection enhancements	Generator Connection	Apr-10	Mar-12	500 kW	N/A	$ 148,680
42	SKYPOWER 7MW AIRPORT SOLAR PROJECT	System Upgrades for connection	New solar at airport requires protection enhancements	Generator Connection	Mar-11	Aug-11	500 kW	N/A	$ 87,007
80	GEA Plan Reclosers	System Upgrades	Thunder Bay Hydro plans to purchase reclosers that are required as REIs for FIT renewable generation projects.	Purchase reclosers	Sep-11	Mar-13	N/A	N/A	$ 207,587
	Subtotal								$ 6,438,424

2012 General Plant Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
67	Single Bucket Truck	A new vehicle provides updated safety, labour and environmental improvements such as improved suspension, new seats, LED lighting, additional internal storage as well as increased reliability, increased fuel economy, reduced emissions, new vehicle warranty and improved appearance (no rust or body panel holes).	Double bucket truck #9 will be 19 years old in 2013 and has 95,000 km, although it is over due to be replaced as per the fleet replacement program, lines has determined that a double bucket will not be required and this smaller aerial device will be more productive and beneficial to the construction work groups for the foreseeable future. This work method / equipment change will essentially save $250,000 over the cost of purchasing a new double bucket truck	A new small 38 foot single bucket truck will replace double bucket truck #9 (1994)	Sep-12	Jun-12	N/A	N/A	$ 120,000
68	i5 Upgrade	Provides additional core functionality for corporate ERP computer system, replaces out of warranty, end of life corporate ERP computer system, and renews O/S related software maintenance agreements on corporate ERP computer system.	The upgrade is needed as computer system at end of life, increase data storage, memory and processor capabilities to address additional corporate computing requirements, and enhance system responsiveness for core line of business computer applications	Replacement or upgrade of all computer hardware for corporate ERP system, renew hardware and software maintenance agreements for new system, configure new system to support existing corporate requirements, reload all O/S and line of business software, and migration of corporate line of business data from old system to new	Dec-11	Jan-12	N/A	N/A	$117,269
	Subtotal								$237,269.02
	Projects <$85,000								$ 4,183,847
	Cash Contributions & Contributions in Kind								($2,022,925)
	TOTAL CAPITAL 2012								**$8,836,615**

1

2013 Distribution Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
69	Durban/Brodie Rebuild	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 65 poles	Sep-13	Dec-13	N/A	N/A	$ 803,871
70	Mary/Heath	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 121 poles	Jan-13	Sep-13	N/A	N/A	$ 1,374,452
62	Ogden/McMurray Rebuild	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Replace 213 poles, 6 pads	Apr-12	Jul-13	N/A	N/A	$ 1,721,369
71	Brunswick/Legion	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 35 poles	Jan-13	Sep-13	N/A	N/A	$ 724,206
72	Huron/Otto - Pole Set only	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 128 poles	Oct-13	Dec-13	N/A	N/A	$ 518,443
73	Elliott/Leslie	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Rebuild 72 poles	Jun-13	Oct-13	N/A	N/A	$ 960,532
74	10M3 to 17M1 Connection @ Main St	Provide ability to transfer load, and reliabilty	Underground connection of 10M3 feeder to 17M1 feeder	Rebuild 3 poles + U/G cable	Jan-13	Dec-13	N/A	N/A	$ 141,119
75	Black Bay/Dewe - Design Contract	Rebuild Area, Convert Voltage	Poles and substation at end of life, restricted conductor	Design work	Jan-13	Dec-13	N/A	N/A	$ 89,342
80	GEA Plan Reclosers	System Upgrades	Thunder Bay Hydro plans to purchase reclosers that are required as REIs for FIT renewable generation projects.	Purchase reclosers	Sep-11	Jul-13	N/A	N/A	$ 187,893
	Subtotal								$6,521,227

2013 General Plant Capital Projects - Projects >$85,000 materiality threshold

Ref #	Description	Purpose	Need	Scope	Start Date	In-Service Date	Load	Cost/Benefit	Actual $
76	RBD Truck	A new vehicle provides updated safety, labour and environmental improvements such as improved suspension, new seats, LED lighting, additional internal storage as well as increased reliability, increased fuel economy, reduced emissions, new vehicle warranty and improved appearance (no rust or body panel holes).	There is a need for another RBD, with the addition of another Capital work crew and the volume of maintenance activites being completed annually. To compensate the utility has rented RBD trucks for the past three years, some years 2 RBDs have been rented to enable the work crews to complete their planned activities. The cost to rent an RBD averages $6500/month, with a purchase cost of $240K, assuming continuous rental payments pay back will occur in approximately 3 years.	A Radial Boom Derrick (RBD)	Apr-12	Mar-13	N/A	N/A	$ 220,345
77	Single Bucket Truck	A new vehicle provides updated safety, labour and environmental improvements such as improved suspension, new seats, LED lighting, additional internal storage as well as increased reliability, increased fuel economy, reduced emissions, new vehicle warranty and improved appearance (no rust or body panel holes).	Although single bucket truck #87 is only 4 years old in 2013 and has 91,000 km, it has been unreliable for use as the after hour on call line vehicle. Lines has determined that truck #87 will be pulled off shift and put into the general line fleet for use by non-critical work groups. The new single bucket will be an additional aerial vehicle.	A new single 42 foot single bucket truck -- this is an additional unit and will push the current maintenance prone shift truck #87 off of shift and into the general line fleet.	N/A	N/A	N/A	N/A	$ 230,000
78	Double Bucket Truck	A new vehicle provides updated safety, labour and environmental improvements such as improved suspension, new seats, LED lighting, additional internal storage as well as increased reliability, increased fuel economy, reduced emissions, new vehicle warranty and improved appearance (no rust or body panel holes).	Double bucket truck #10 will be 20 years old in 2013 and has 81,000 km and is over due to be replaced as per the Fleet replacement program.	A new 55 foot material handler double bucket truck	N/A	N/A	N/A	N/A	$ 375,000
79	Garage	The new facility will incorporate improved safety aspects, elevated ceiling height with overhead crane, enhanced lighting, ventilation and accessibility, and elevated storage facilities incorporated within the garage, improved industrial hygiene via automatic air exchange devices.	This project is necessary as the existing maintenance facility and cold storage (Annex) is 80 years old and has numerous areas of concern (safety, structural, environmental, ergonomics and operational).	The utility plans to contract out the demolition of the cold storage section of the existing 1932 vintage fleet maintenance building and design and build a new stand-alone maintenance facility as per the general requirements of the utility.	N/A	N/A	N/A	N/A	$3,303,500
	Subtotal								$4,128,845
	Projects <$85,000								$2,472,105
	Cash Contributions & Contributions in Kind								($989,985)
	TOTAL CAPITAL 2013								**$12,132,192**

1

2012 & 2013 Project related to GEA

Based on Thunder Bay Hydro's Green Energy Act ("GEA") Plan, the utility plans to purchase 15 reclosers between 2012 and 2013 which are for both Renewable Energy Standard Offer Program ("RESOP") or Feed-In Tariff ("FIT") related renewable generation projects. Reclosers in relation to RESOP projects are to be 100% funded via Thunder Bay Hydro's rate base; however, as per instruction of EB-2009-0349 Determination of Direct Benefits, Thunder Bay Hydro intends to recover the FIT recloser costs as determined by a basic direct benefit assessment via a funding adder for its direct costs and the remainder from its customers.

Table 2-3.4 below shows the capital expenditures forecasted to be spent in 2012 and 2013 and how much of the cost would be applicable to Thunder Bay Hydro customers.

Table 2-3.4 – Capital Expenditure Forecasted to be spent in 2012 and 2013

Year	**2012**	**2013**	**2013**	**2013**
	CGAAP	CGAAP	MCGAAP	MCGAAP
Gross Investment	$415,175	$622,764	$187,893	$375,786
Activity Definition (by the DSC)	"Enhancement"	"Enhancement"	"Enhancement"	"Renewable Enabling Improvement"
External Funding	$0	$0	$0	$353,239
Funded by Thunder Bay Hydro's Rate Base	$415,175	$375,786	$187,893	$22,547
Number of Reclosers	6	9	3	6
Average Cost/Recloser	$69,196	$69,196	$62,631	$62,631

The details related to this project can be found in Thunder Bay Hydro's Basic GEA Plan in Appendix 2-B, followed by the Ontario Power Authority's Letter of Communication response in Appendix 2-C.

ASSET MANAGEMENT PLAN SUMMARY

Thunder Bay Hydro provides electricity to the residents and businesses within the defined city limits of Thunder Bay, Ontario. In order to meet its customer's service expectations, Thunder Bay Hydro must effectively manage its electrical distribution assets from procurement, through service life, and into retirement.

Thunder Bay Hydro's vision is to be regarded as a provincial leader in infrastructure management and customer satisfaction. To this end, Thunder Bay Hydro's Asset Management Policy is to; construct and maintain a safe, environmentally responsible, sustainable and economical distribution system that reliably delivers high quality electricity to its customers while optimizing Thunder Bay Hydro's shareholder's long term return on investment. Thunder Bay Hydro shall comply with all applicable legal, regulatory, and environmental requirements and will perform all functions with public and employee safety as its first priority.

Thunder Bay Hydro will achieve the objectives of the Asset Management Policy by applying appropriate asset management systems which facilitate the planning, operation, maintenance, and retirement of assets. These systems will;

- Include facets of leading asset management practices;
- Establish long-term asset management strategies and asset objectives which are consistent with the priorities of the corporation;
- Monitor and trend the delivery of the asset management objectives and targets while reviewing the achievement of their intended benefits;
- Incorporate regular audits and formal management reviews designed to seek and implement continual improvement.

Further, all asset management initiatives implemented by Thunder Bay Hydro to practically fulfill the intentions of the Asset Management Policy shall subject the prioritization of their projects and activities to the degree with which the following objectives are satisfied:

1) Ensuring the health and safety of the public and the Thunder Bay Hydro employee;

2) Mitigating existing or future introduction of environmental threats;

3) Compliance with regulatory and legal obligations;

4) Fulfillment of customer demand work;

5) Retirement of assets which have reached the end of their useful life; and

6) Improvement of operational efficiency.

Asset Management Initiatives

The following initiatives combine to form Thunder Bay Hydro's Asset Management Plan. These initiatives are complimentary to one another, often fulfilling, in whole or in part, the objectives of a parallel activity. In no particular order, the Thunder Bay Hydro asset management initiatives are:

- Asset Condition Assessment;
- Forestry Management Program;
- PCB Management Program;
- Underground Asset Renewal;
- 12kV Distribution Station Refurbishment;
- Above Ground Asset Renewal;
- Voltage Conversion of 4kV to 25kV.

A brief description of these initiatives and their associated budgets are described herein. For further detail and justification, refer to the "Thunder Bay Hydro Electricity Distribution Inc. – Asset Management Plan" in Appendix 2-A.

Asset Condition Assessment

The Asset Condition Assessment is the primary means by which Thunder Bay Hydro is able to prioritize future capital and maintenance efforts. This assessment fulfills Thunder Bay Hydro's obligations as set out in the Distribution System Code (the "Code"), monitors the effectiveness of past maintenance and capital activities, targets the efforts of the maintenance regime, and benchmarks the objectives of the long term capital replacement programs.

The Asset Condition Assessment pertains to the categorical evaluation of the Thunder Bay Hydro distribution assets by qualified Thunder Bay Hydro staff[1]. This assessment is primarily undertaken for the purposes of risk management and hazard mitigation. The Asset Condition Assessment is an essential driver for Thunder Bay Hydro decisions on maintenance levels, maintenance requirements, and decisions regarding the selection and scope of capital projects. Ultimately, the objective of this assessment is to monitor physical indicators of asset degradation or malfunction, correlate these observations to distribution system reliability statistics and maintain or replace these assets in a timely and economical fashion. Performance of the Asset Condition Assessment in this manner satisfies the following Thunder Bay Hydro asset management objectives:

- Ensuring the health and safety of the public and the Thunder Bay Hydro employee;
- Mitigation of existing or potential environmental threats;
- Compliance with regulatory and legal obligations;
- Timely retirement of end of life assets; and,
- Continual improvement of operational efficiency.

For the purposes of manageability and to account for the disparity among assets, the execution of the Asset Condition Assessment has been subdivided as follows:

- Overhead Inspection and Risk Assessment
- Underground Inspection and Risk Assessment
- Substation Inspection and Risk Assessment

The Overhead Inspection and Risk Assessment encompass Thunder Bay Hydro's inspection methods pertaining to the following assets:

- Utility poles and associated framing (framing includes wood and steel cross arms, insulators, standoffs, brackets, and guying);
- Overhead distribution lines including primary and secondary circuits;

[1] Internally referred to as the WHOLE risk assessment representing; Workplace specific, Health and safety, Operational, Legislative, and Environmental.

- Overhead distribution transformers;
- Overhead distribution switches (includes: load break, air break, in-lines, and reclosers).

The Underground Inspection and Risk Assessment encompass Thunder Bay Hydro's inspection methods pertaining to the following assets:

- Pad mounted and vault enclosed distribution transformers;
- Pad mounted and vault enclosed switching assets (i.e. switchgear, vac-pacs);
- Underground network conductors.

The Substation Inspection and Risk Assessment encompass Thunder Bay Hydro's inspection methods pertaining to the following assets:

- Substation enclosure/yard/building, grounding/bonding and fencing;
- Breakers, reclosers, fusing, switches and switchgear;
- Power transformers;
- Auxiliary station equipment (AC and DC systems, protective relaying, SCADA equipment, remote terminal units, metering, instrument transformers, lightning arrestors, insulators, bus connections, steel structures, foundations, oil containment, ducts / conduits etc.).

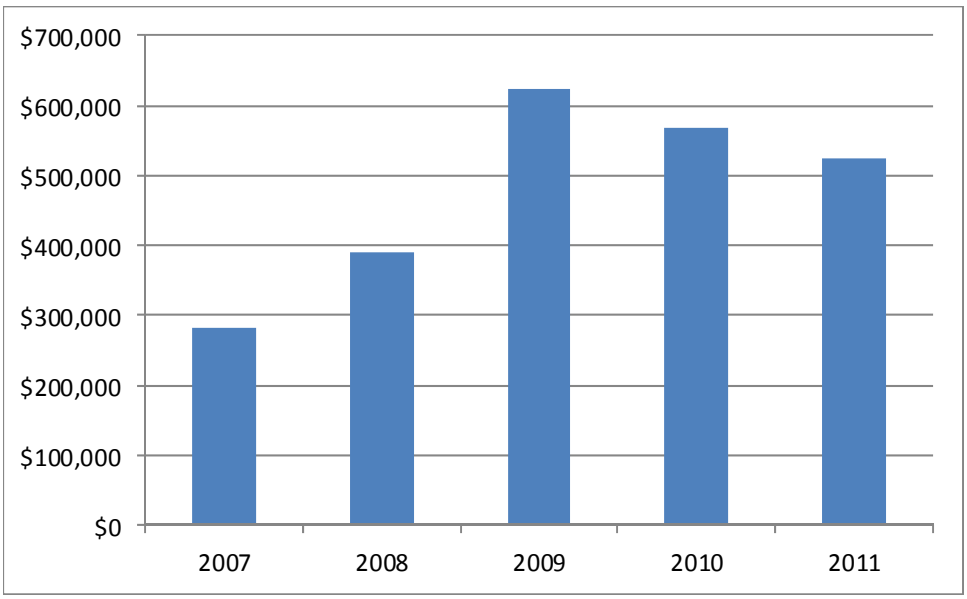
Forestry Management Program

The Forestry Management Program monitors and manages the approximately 869 km of thoroughfare occupied by Thunder Bay Hydro distribution lines for vegetation encroachment. This program is designed to systematically target areas of severe vegetation infiltration while still supporting crews during storm events, maintenance activities, and large scale capital construction.

Until recently, Thunder Bay Hydro's forestry management was conducted on a small scale and on an 'as needed' basis. This was in keeping with an effort to maintain customer's electricity rates as low as possible. This small scale effort did not address Thunder Bay Hydro's vegetation management requirements at a sustainable level.

Thunder Bay Hydro is presently executing an escalated vegetation abatement strategy in order to effectively manage the overgrowth backlog resulting from the earlier small scale effort. The historical Forestry Operations budget is shown in Table 2-3.5 below.

Table 2-3.5 – Historical Forestry Operations Budget (CGAAP)



Forestry Management Contractor costs

The PCB Management Program

The Polychlorinated Biphenyls (PCB) Management Program is a legislated initiative in response to the health and environmental risks associated with assets containing specific levels of PCBs. This prioritized program targets the removal of select quantities of PCB contaminated assets that are in excess of 50 parts per million (ppm) PCB annually, with an ultimate goal of having all >50 ppm PCB assets removed from service by 2018.

The estimated cost of compliance over the life of the program is as found in **Table 2-3.6 below**.

Table 2-3.6 - PCB Management Program: Estimated Cost of Compliance

Year	Actual and Anticipated Number of U/G Transformers Replaced	Actual and Anticipated Number of O/H Transformers Replaced	Actual Transformer Replacement OM&A Cost (labour, trucking overheads etc.)	Actual Transformer Replacement Capital Cost	Combined OM&A and Capital Transformer Replacement Cost ($6,000 per transformer)	Actual and Anticipated Oil Destruction Costs for >2 PPM PCB (2011-2018) (2008-2010 TBH only destroyed >50 PPM PCB oil)	Actual and Anticipated Destruction Costs of >50 PPM PCB Solid Waste Material	Actual and Anticipated Transport Costs	Actual and Anticipated Cost Totaled
2009	6	44	$162,206.12	$101,412.28	$263,618.40	$17,913.02	$9,684.59	$8,770.00	$299,986.01
2010	3	23	$121,296.48	$41,908.65	$163,205.13	$6,378.75	$1,248.45	$3,500.00	$174,332.33
2011	12	13	$97,882.08	$59,605.70	$157,487.51	$25,107.75	$1,568.90	$6,241.04	$190,405.47
2012	12	11	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2013	5	18	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2014	0	23	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2015	0	23	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2016	0	23	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2017	0	23	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2018	0	17	--	--	$102,000	$29,645.63	$2,000.00	$7,000.00	$140,645.63
TOTAL									**$1,867,369.44**
	Grey shaded area denotes actual expenditures for PCB activities completed for the applicable years								
The current plan total incorporates overall program cost actuals for 2009 – 2011 and includes a revised transformer replacement cost of $6,000 vs the original plan amount of $10,000									

Underground Asset Renewal Program

The Thunder Bay Hydro underground distribution network consists of underground cables, pad mounted transformers, and switching assets. Based on condition assessments and the events of the cable testing program, Thunder Bay Hydro has determined that its greatest risk lies with the potential failure of substantially aged, heavily loaded arterial cable sections. In addition to the risk associated with arterial cable sections, Thunder Bay Hydro also acknowledges the elevated risk associated with aged subdivision networks as a whole which may contain unacceptably long service loops, brittle load break elbows (which often fail upon operation), and a number of splices due to past mechanical or electrical damage.

For the purposes of efficiency and customer convenience, it is Thunder Bay Hydro's intention to systematically rebuild subdivision networks as a whole as they approach end of life however, in the near term (3 year horizon) Thunder Bay Hydro intends to target the replacement of its most heavily aged underground conductors based on projected customer impact should they be allowed to fail. The intent of this strategy is to limit customer exposure to long term/high impact outages, reduce the cost of inevitable asset replacements by conducting them on regular time where possible rather than as emergency conditions dictate, and enable forecasted budgeting of asset replacements rather than reactionary expenditure in the case of uncontrolled failure.

The projected budget to facilitate this program is found in Table 2-3.7.

Table 2-3.7 - Underground Asset Renewal Projected Budget Over 2 Years 12kV Distribution Station Refurbishment (MCGAAP)

Year	U/G Replacement Costs	Year	U/G Replacement Costs
2012	$0	2023	$4,560,000
2013	$141,119	2024	$4,560,000
2014	$480,000	2025	$4,560,000
2015	$1,200,000	2026	$4,560,000
2016	$1,800,000	2027	$4,560,000
2017	$2,600,000	2028	$4,560,000
2018	$3,400,000	2029	$4,560,000
2019	$4,200,000	2030	$4,560,000
2020	$4,560,000	2031	$4,560,000
2021	$4,560,000	2032	$4,560,000
2022	$4,560,000	2033	$4,560,000

Thunder Bay Hydro owns and operates four 12kV distribution substations. In addition to providing service to approximately 3,400 rural customers, this network also supports the 3.2MW Mapleward Renewable Generating Station. Thunder Bay Hydro currently has no intention of retiring the 12kV voltage class and as such, the 12kV infrastructure must be maintained in a sustainable manner.

Thunder Bay Hydro acknowledges that a catastrophic power transformer failure on the 12kV network would cause substantial inconvenience, lost revenue, and potential health and safety risk to its customers. Furthermore, failure to provide an anticipatory budget for the replacement of these assets will result in a significant unplanned capital expense not already accounted for in Thunder Bay Hydro's rate strategy.

Thunder Bay Hydro's objective is to plan for capital replacement of the 12kV substation power transformers such that the asset is replaced in a timely manner, prior to failure yet at the perceived end of useful life.

The projected budget for the activities associated with this initiative is found in Table 2-3.8.

Table 2-3.8 - 12kV Substation Power Transformer Program Budget Above Ground Asset Renewal Program (MCGAAP)

Substation	Transformer Replacement Year	Cost Estimate
Mapleward DS	2017	$500,000
Alice DS	2019	$500,000
Balsam DS	2022	$500,000
Broadway DS	2029	$500,000
	Estimated Total:	$2,000,000

The Thunder Bay Hydro overhead distribution network consists of overhead conductors, distribution transformers, poles, associated framing/guying infrastructure, reclosers and switching assets. Based on condition assessments and asset demographic studies, Thunder Bay Hydro has determined that its greatest risk lies with the potential failure of substantially aged assets (particularly the structural components), the questionable adequacy of legacy construction practices, and the approaching end of life of the 4kV substation assets.

For the purposes of efficiency (operational and economic) and customer convenience, it is Thunder Bay Hydro's intention to systematically rebuild and restore the overhead distribution network by targeting bulk zones of depreciated assets for replacement or restoration where

possible. Selection of projects is based upon Thunder Bay Hydro's established Capital Project ranking criteria in conjunction with Thunder Bay Hydro's developing vision for the ultimate state of the distribution network.

The intent of this program is to limit customer exposure to avoidable outages due to asset failure, ensuring the safety of staff and/or the public, maintain or enhance reliability metrics where possible, limit or eliminate operational or maintenance liabilities, and enable forecasted budgeting of asset replacements rather than reactionary expenditures in the case of uncontrolled failures.

Due to the substantial ageing of the 4kV asset population and the inherent efficiencies gained in the execution of such a project, Thunder Bay Hydro is proceeding with a complete conversion of the 4kV sub-network to a standardized, 25kV primary system. In order to also address heavily aged assets which fall outside of the scope of the annual conversions, Thunder Bay Hydro will continue to conduct suspect pole replacements on a 'concern' driven basis. Over the past three years, suspect pole changes driven by concerns have averaged 120 units per year.

The projected budget for the activities associated with this initiative is found in Table 2-3.9.

Table 2-3.9 - Thunder Bay Hydro Forecasted Above Ground Asset Renewal Budget (MCGAAP)

Year	Overhead Asset Replacement Cost	Year	Overhead Asset Replacement Cost
2012	$6,088,073	2023	$8,050,000
2013	$7,232,471	2024	$8,050,000
2014	$8,022,500	2025	$8,050,000
2015	$8,075,000	2026	$8,050,000
2016	$8,335,000	2027	$8,050,000
2017	$8,330,000	2028	$8,050,000
2018	$8,330,000	2029	$8,050,000
2019	$8,330,000	2030	$7,475,000
2020	$8,330,000	2031	$6,900,000
2021	$8,330,000	2032	$6,325,000
2022	$8,050,000	2033	$5,462,500

As described in the Asset Management Plan (Appendix 2-A), Thunder Bay Hydro's three year forecast (Test Year plus two subsequent years) for capital expenditures can be found in Table 2-3.10.

Table 2-3.10 - Capital Program Budget Forecast - Near Term (2012 – 2015 MCGAAP)

YEAR	PROJECT	PROJECT TYPE	ACTIVITY	PROJECTED COST
2012	Brown/Isabella	Overhead Voltage Conversion	Overhead Construction	$1,764,076
	Brock/Ford	Overhead Voltage Conversion	Overhead Construction	$1,092,369
	Georgina/Francis	Overhead Voltage Conversion	Overhead Construction	$1,096,922
	Ogden/McMurray	Overhead Voltage Conversion	Overhead Construction	$817,776
	Durban/Brodie	Overhead Voltage Conversion	Design	$108,790
	Huron/Otto	Overhead Voltage Conversion	Design	$30,178
	Clayte/Buriss	Overhead Voltage Conversion	Design	$43,661
	Balsam/Minot	Overhead Voltage Conversion	Design	$99,655
	Dawson/Rockwood	Overhead Voltage Conversion	Design	$74,538
	Elliott/Leslie	Overhead Voltage Conversion	Design	$78,387
	Elm/Campbell	Overhead Voltage Conversion	Design	$89,883
	Redmond/Egan	Overhead Voltage Conversion	Design	$132,270
	Brunswick/Legion	Overhead Voltage Conversion	Design	$0
	Dacre/Leslie	Overhead Voltage Conversion	Design	$42,472
	MacDougall/Court	Overhead Voltage Conversion	Design	$68,996
	Unplanned Capital	Unplanned	Unplanned	$68,564
	Underground Cable Testing	Condition Assessment	Underground Cable Testing	$227,856
	Maintenance Replacements	Maintenance	Maintenance Replacements	$1,116,419
	Total			**$6,952,812**
YEAR	**PROJECT**	**PROJECT TYPE**	**ACTIVITY**	**PROJECTED COST**
2013	Durban/Brodie	Overhead Voltage Conversion	Overhead Construction	$803,690
	Mary/Heath	Overhead Voltage Conversion	Overhead Construction	$1,374,196
	Ogden/McMurray	Overhead Voltage Conversion	Overhead Construction	$1,720,804
	Brunswick/Legion	Overhead Voltage Conversion	Overhead Construction	$724,103
	Huron/Otto	Overhead Voltage Conversion	Overhead Construction	$518,466
	Elliott/Leslie	Overhead Voltage Conversion	Overhead Construction	$960,258
	Dacre/Leslie	Overhead Voltage Conversion	Design	$70,717
	Black Bay/Dewe	Overhead Voltage Conversion	Design	$89,342
	McPherson/Christie	Overhead Voltage Conversion	Design	$49,609
	10M3-17M1 Tie	System Imropvement	Underground Construction	$141,124
	Unplanned Capital	Unplanned	Unplanned	$93,275
	Maintenance Replacements	Maintenace	Maintenance Replacements	$1,129,598
	Total			**$7,675,182**

YEAR	PROJECT	PROJECT TYPE	ACTIVITY	PROJECTED COST
2014	Clayte-Buriss	Overhead Voltage Conversion	Overhead Construction	$2,479,128
	Huron-Otto	Overhead Voltage Conversion	Overhead Construction	$1,011,601
	Dawson-Rockwood	Overhead Voltage Conversion	Overhead Construction	$1,003,348
	Dacre-Leslie	Overhead Voltage Conversion	Overhead Construction	$1,780,526
	Elm-Campbell	Overhead Voltage Conversion	Overhead Construction	$495,600
	Northern-Vickers	Overhead Voltage Conversion	Design	$69,030
	McPherson-Christie	Overhead Voltage Conversion	Design	$42,900
	Isabella-James	Overhead Voltage Conversion	Design	$39,060
	21F6 Rebuild	Overhead Voltage Conversion	Design	$73,710
	21F5 Rebuild	Overhead Voltage Conversion	Design	$15,540
	10M8 Reconfiguration & Reconductoring	Underground Network Rebuild/Improvement	Underground Construction	$480,000
	Unplanned Capital	Unplanned	Unplanned	$100,000
	Maintenance Replacements	Maintenance	Maintenance Replacements	$1,150,000
	Total			**$8,740,443**
YEAR	**PROJECT**	**PROJECT TYPE**	**ACTIVITY**	**PROJECTED COST**
2015	Balsam-Minot	Overhead Voltage Conversion	Overhead Construction	$1,833,345
	Dewe-Rita	Overhead Voltage Conversion	Overhead Construction	$2,568,350
	McKenzie-Dease	Overhead Voltage Conversion	Overhead Construction	$472,306
	Elm-Campbell	Overhead Voltage Conversion	Overhead Construction	$822,517
	Black Bay-Dewe	Overhead Voltage Conversion	Overhead Construction	$831,600
	Redmond-Egan	Overhead Voltage Conversion	Overhead Construction	$394,800
	21F1 Rebuild	Overhead Voltage Conversion	Design	$64,740
	McDougall-Court (PH1&PH2)	Overhead Voltage Conversion	Design	$68,996
	Cumming-Brodie	Overhead Voltage Conversion	Design	$50,310
	Finlayson-Brodie	Overhead Voltage Conversion	Design	$30,030
	Cameron-Vickers	Overhead Voltage Conversion	Design	$25,740
	10M7 Reconfiguration & Reconductoring	Underground Network Rebuild/Improvement	Underground Construction	$707,500
	U/G Replacement	Underground Network Rebuild/Improvement	Underground Construction	$480,000
	Unplanned Capital	Unplanned	Unplanned	$100,000
	Maintenance Replacements	Maintenance	Maintenance Replacements	$1,150,000
	Total			**$9,600,234**

BUSINESS APPLICATIONS:

The Information Systems Department (ISD) personnel oversee the acquisition, installation, operation, maintenance, availability and security of the Thunder Bay Hydro's computer hardware, software, data and network resources. They provide support services to all departments for resources under the ISD scope of responsibility. ISD operates following generally accepted Information Technology industry standards. ISD is currently supporting over 200 users utilizing PC workstations, thin-clients, laptops and wireless devices to connect to the network resources. The ISD group actively pursues implementation of new technologies and services to support Thunder Bay Hydro moving forward.

Software:

- Support of computer operating systems, business applications, industry specific packages, design and geographic applications and standard integrated office products (deployment, installation, version upgrades, licensing, maintenance).

- Customized departmental and Thunder Bay Hydro applications are developed, tested, implemented and supported using standard development tools.

- Maintain and update current levels of virus protection, security software updates and email filtering for security/virus risks.

- Direct and coordinate out of scope/expertise development to third party vendors.

Hardware:

- Configure servers, pc workstations, thin-clients, laptops, printers and wireless devices to serve as or connect to network resources (deployment, firmware upgrades, licensing, and maintenance).

- Maintain system servers for primary and backup domain controllers, database applications, data repository and printer sharing and browser based business applications.

- Business application and data file servers configured with real time data redundancy for fail over recovery and storage expansion.

- Replacement/repair of failed devices or direct undeterminable hardware failures and problems to third party vendors.

- Asset tracking and rationalization to ensure optimal deployment and viability.

Network Infrastructure:

- Implement, manage and maintain network connectivity (routing, switches, firewall, cable/wireless).

- Control network access (security, passwords, remote access), group and individual access.

- LAN/WAN design, implementation and support of ethernet and fiber optic resources.

Data Management:

- Maintain daily, weekly, and monthly data archives utilizing tape backup and other media for servers and other critical applications (offsite storage for disaster recovery).

- Ensure the integrity and security of the data by following industry standards and implementing legislated privacy regulation controls (user/user group data access restrictions).

Help Desk and Training:

- Provides basic, intermediate and advanced levels of on-site support and trouble-shooting to end users for any software, hardware and network resource connectivity issues under the ISD scope of responsibility.

- Train employees on computer basics helping them to utilize the tools they have available through their office productivity software and customized in-house developed applications.

- Cross training and knowledge transfer among ISD personnel to facilitate broad range support.

Research and Development:

- Maintain a functional understanding of developments within the Information Technology industry and current trends in the Thunder Bay Hydro's operating environment.

- Attend training and education forums in new technology and evaluate new products and services for Thunder Bay Hydro compatibility.

- Plan to implement new technologies to ensure cost effective solutions are leveraged to support the corporate objectives.

Procurement/Disposal:

- Responsible for setting standards, selecting specific products, detailing requisition specifications, engaging third party vendors, license management, maintenance contract management and invoice reconciliation for all technology purchase related activities within Thunder Bay Hydro.

- Lifecycle tracking for assets to determine end of life disposal.

OTHER COMPUTER HARDWARE AND SOFTWARE

Computer Hardware:

Computer equipment is used in all departments of utility operations and is a key enabler in Thunder Bay Hydro initiatives to maintain and improve reliability, improve customer service and reduce costs.

New and replacement computer hardware consists of the following equipment:

- Desktops
- Laptops
- Monitors
- Servers
- Enterprise Main Frame
- Printers
- Network Infrastructure and Security

Thunder Bay Hydro utilizes a three-year life cycle for all computer and network infrastructure hardware with the exception of printers, which are extended to reasonable life expectancy, typically 5 years. Software is upgraded as required to maintain productivity, functionality and, where reasonable, currency within Thunder Bay Hydro's ERP model. It is common industry practice to keep both the hardware and software environments up to date. Increased incidence of hardware failure reduced technical support, new technical standards and higher performance requirements of current operating systems and applications drive this lifecycle. The upgrade of aging servers and consolidation of multiple servers to a more manageable volume provide cost effective migration of workload with higher performance efficiencies and lower maintenance costs.

Other benefits of replacing computer equipment and adding new equipment include:

- Reducing the dependence on ISD resources to support older equipment;
- Ensuring third party support is available when required;
- Taking advantage of new technologies and increasing server utilization;
- Empowering employees to be more productive with the right equipment to do their jobs;
- Improving access to data and other information;
- Adhering to best practices; and
- Allowing for growth

Computer Software:

Computer software, whether operating system software or application software, are programs written in machine-readable languages, that control the operations of hardware or that enable users to perform certain tasks on computers.

The operating system software controls the hardware and manages its internal functions: controls input, output and storage and, handles its interaction with application programs. Application software enables users to accomplish particular tasks.

Today, the functioning of computer software is tied closely into the hardware it resides on and it is important that the specification of any PC or Server is appropriate for the software being installed.

Benefits of adding or replacing computer software include:

- Improvements in productivity from software enhancements;
- Empowering employees with the latest software technologies;
- Keeping up to date with industry standards;
- Ease of integration to other applications;
- Reduced costs using common operating system;
- Ensuring third party support is current
- Taking advantage of higher levels of security
- Reduced dependence on ISD resources; and
- Improved tools for web development/design.

Adding and replacing computer software systems is necessary to support the running of all application programs. Software provides the support necessary for computers to interact with each other. Business Applications software processes transactions that are essential to running the business.

CAPITALIZATION POLICY

Thunder Bay Hydro has historically applied the following general capitalization policies and principles based on Canadian Generally Accepted Accounting Principles ("CGAAP"), as well as guidelines set out by the Ontario Energy Board, where applicable. Going forward capitalization will conform to the Modified International Financial Reporting Standards (MIFRS). The information found in this section applies to capitalization under CGAAP only. Changes due to modification of capitalization and depreciation policies to be more in line with MIFRS are described in Tab 4 - Summary of Changes as a Result of Modifying Capitalization and Depreciation Policy "Modified" CGAAP (MCGAAP).

The amount to be capitalized is the cost to acquire or construct a capital asset, including any ancillary costs incurred to place a capital asset into its intended state of operation.

- Assets that are intended to be used on an on-going basis and are expected to provide future economic benefit greater than one year will be capitalized.
- Expenditures that create a physical betterment or improvement of the asset will be capitalized.
- With respect to transportation equipment all costs associated with placing a vehicle into service are capitalized.

GUIDELINES FOR CAPITALIZATION

Capital Assets

Capital Assets include tangible assets which include property, plant, and equipment provided they are held for use in the production or supply of goods and services. A capital expenditure must 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 identified as assets that lack physical substance.

Betterment

A "betterment" is a cost which enhances the service potential of a capital asset 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.

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 should be charged to an operating account.

CAPITAL ASSET COST

Cost

Cost is the amount of consideration given up to acquire, construct, develop or better a capital asset. Capital assets will be recorded at the fully allocated cost.

Fully Allocated costs

Fully allocated costs include all expenditures necessary to put a capital asset in service including all overhead cost based on full absorption costing.

Thunder Bay Hydro uses the following "Overhead/Burden" Accounts:

<u>Corporate Benefits</u>

- This account accumulates the costs of fringe benefits associated with labour such as dental benefits, medical benefits, long-term disability, vested sick leave and the Employee Assistance Program. These costs are distributed to an employee's Division/Department as a percentage of their regular wages as they are paid during the year.

<u>Downtime</u>

- This account accumulates the related payroll costs for the PLE group for payroll costs associated with vacations, statutory holidays, sick leave and other leaves of absence, employee training, safety programs and any other unproductive labour

time. These costs are allocated to Operating, Maintenance or Capital expenditures as a % based on PLE work order labour costs.

Material costs

- This account accumulates the related costs associated with the Purchasing and Stores Departments. The overhead is 75% of the Purchasing Department and 100% of Stores. These costs include payroll costs of employees directly related with the purchasing and stores, and purchasing and stores operation costs. These costs are allocated as a percentage of materials issued through stores.

Supervisory

- This account accumulates the related payroll and operation costs related to the PLE Supervisor group. These costs are allocated to Operating, Maintenance or Capital expenditures as a % based on PLE work order labour costs.

Engineering

- This account accumulates the costs associated with the costs of the engineering operation, including engineering staff and their support staff payroll costs, facilities, equipment and supplies. These costs are allocated to Operating, Maintenance or Capital expenditures as a % based on PLE work order labour costs.

Rolling Stock Operations

- This account accumulates the costs associated with maintaining trucks, equipment and trailers etc. These costs include payroll costs related to the mechanics and common rolling stock operation costs such as fuel, lubricants, repairs, parts, insurance as well as office and computer costs directly related to the rolling stock operations. These costs are allocated based on a per hour available for use basis.

All overhead charges are reviewed regularly. Any residual balances remaining after regular distribution are cleared to the applicable capital, operating or maintenance accounts depending on the actual occurrence of the cost allocation relationships.

Amortization

Capital assets are amortized based on a method and life set by the OEB which is considered a suitable indicator of estimated useful life for the electrical distribution industry.

Capital Spares

Spare transformers and meters will be accounted for as capital assets since they form an integral part of the reliability program for a distribution system. These spares are held for the purpose of backing up transformers and meters in-service for a distribution system.

SERVICE QUALITY & RELIABILITY PERFORMANCE

Thunder Bay Hydro's achieved levels of service quality for the year 2009 through 2011 are provided in **Appendix 2-D.** Thunder Bay Hydro's performance has been above the established standard for these reported years.

ALLOWANCE FOR WORKING CAPITAL

OVERVIEW AND CALCULATION BY ACCOUNT

In calculating the Working Capital Allowance ("WCA") for 2012 and 2013, Thunder Bay Hydro used the default of 13% of the cost of power and controllable expenses. This is based on the Board's update to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications –Allowance for Working Capital, dated June 28, 2012. Table 2-4.1 below shows the changes in working capital allowance from 2009 to 2013.

Table 2-4.1 – Summary of Working Capital Allowance

	2009 Board approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test (CGAAP)	2013 Test (MCGAAP)
Distribution Expenses - Operation	2,789,357	2,703,387	2,866,616	3,184,794	3,057,560	3,319,533	3,559,704
Distribution Expenses - Maintenance	3,049,733	3,177,750	3,300,110	2,786,514	3,885,577	3,109,691	3,951,962
Billing and Collecting	2,244,506	1,996,320	2,067,993	1,945,612	2,197,135	2,132,818	2,134,694
Community Relations	228,339	151,777	188,598	107,051	129,319	141,862	141,862
Administrative & General Expenses	3,623,127	3,820,604	3,927,036	4,035,999	4,499,372	4,714,091	4,894,193
Taxes Other than Income Taxes	170,284	178,000	60,000	3,752	-	-	-
Less : Capital Taxes within 6105	170,284	178,000	60,000	3,752	-	-	-
Less: Amortization included above	290,386	238,995	268,332	247,781	264,134	263,569	263,569
Total Eligible Distribution Expenses	11,644,677	11,610,842	12,082,021	11,812,190	13,504,829	13,154,426	14,418,846
Power Supply Expenses	78,227,629	74,346,574	78,449,275	85,711,366	96,806,595	97,020,439	97,020,439
Total Working Capital Expenses	89,872,307	85,957,416	90,531,296	97,523,555	110,311,424	110,174,865	111,439,285
Working Capital Allowance	13,480,846	12,893,612	13,579,694	14,628,533	16,546,714	14,322,732	14,487,107
Working Capital Allowance %	15%	15%	15%	15%	15%	13%	13%

Thunder Bay Hydro's working capital allowance is forecast to be $14,487,107 for 2013 based on the "13% Allowance Approach" outlined on page 17 of the Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28, 2012, which is 13% of the sum of the Cost of Power and Controllable Expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General).

Cost of Power Forecast

Thunder Bay Hydro's cost of power forecast for 2012 and 2013 were derived by applying the appropriate rates for the period in question to the forecasted energy sales and demand. More specifically, the following steps were followed:

Energy Purchases

The 2012 and 2013 forecasted sales in kWh and kW, produced by the load forecasting model and adjusted for the impact of CDM activities were used. To calculate the cost of commodity, the load forecast for each year was allocated between non-RPP and RPP kWh sales based on 2011 actuals. Both volumes for both years were uplifted by the proposed 2013 Total Loss Factor (TLF) of 1.0389 as calculated in Appendix 2-R of the Chapter 2 Appendices. Since the TLF for 2012 is unknown, Thunder Bay Hydro believes it to be reasonable to apply the 5 year average to 2012 as calculated in Appendix 2-R.

The loss adjusted RPP forecast for both 2012 and 2013 are multiplied by the most current RPP Price issued by the Board which is found in the *Regulated Price Plan Price Report May 1, 2012 to April, 30, 2013* dated April 2, 2012. The rate used is the average supply cost for a RPP consumer which is currently $0.08069/kWh. The loss adjusted non-RPP forecast for both 2012 and 2013 are multiplied by the sum of the Global Adjustment as listed in the Board's Price Report above ($0.05772/kWh) and the applicable "term average" HOEP forecast provided by Navigant dated April 9, 2012 (2012=$0.02105/kWh; 2013=$0.02362/kWh).

Network and connection costs are determined by using the loss adjusted load forecast and applying the approved rates from the Board's decision in EB-2011-0197 to the 2012 applicable volumes and the proposed 2013 rates as calculated in the Retail Transmission Service Rates excel file. The Wholesale Market Service cost and Rural Rate Assistance costs are determined by using the loss adjusted load forecasts for 2012 and 2013 at $0.0052/kWh and $0.0011/kWh respectively.

As discussed above, Thunder Bay Hydro has used the most current rates to calculate the cost of power, understanding that these rates may require updating as new rates become effective during the Cost of Service Application process. Table 2-4.2 shown below is the calculated 2012 and 2013 Cost of power (CGAAP and MCGAAP):

Table 2-4.2 - Cost of Power

2012 Load Foreacst	**kWh**	**kW**	**2011 %RPP**
Residential	340,342,141		90%
General Service < 50 kW	131,576,021		86%
General Service 50 to 999 kW	287,997,314	782,499	16%
General Service > 1,000 kW	182,342,067	565,225	1%
Street Lighting	11,127,205	31,343	0%
Sentinel Lighting	121,134	336	100%
Unmetered Scattered Load	1,982,032		81%
TOTAL	**955,487,915**	**1,379,404**	
	0	0	

Electricity - Commodity RPP	**2012**	**2012 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2012**	
Residential	307,755,936	1.0389	319,717,364	$0.08069	$25,797,994
General Service < 50 kW	112,658,596	1.0389	117,037,253	$0.08069	$9,443,736
General Service 50 to 999 kW	46,236,814	1.0389	48,033,882	$0.08069	$3,875,854
General Service > 1,000 kW	1,784,886	1.0389	1,854,258	$0.08069	$149,620
Street Lighting	0	1.0389	0	$0.08069	$0
Sentinel Lighting	121,134	1.0389	125,843	$0.08069	$10,154
Unmetered Scattered Load	1,604,915	1.0389	1,667,292	$0.08069	$134,534
TOTAL	**470,162,281**		**488,435,892**		**$39,411,892**

Electricity - Commodity Non-RPP	**2012**	**2012 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**		**2012**	
Residential	32,586,206	1.0389	33,852,721	$0.07877	$2,666,579
General Service < 50 kW	18,917,425	1.0389	19,652,681	$0.07877	$1,548,042
General Service 50 to 999 kW	241,760,500	1.0389	251,156,910	$0.07877	$19,783,630
General Service > 1,000 kW	180,557,182	1.0389	187,574,826	$0.07877	$14,775,269
Street Lighting	11,127,204	1.0389	11,559,681	$0.07877	$910,556
Sentinel Lighting	0	1.0389	0	$0.07877	$0
Unmetered Scattered Load	377,118	1.0389	391,775	$0.07877	$30,860
TOTAL	**485,325,634**		**504,188,594**		**$39,714,936**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2012**	
Residential		kWh	353,570,085	$0.0064	$2,262,849
General Service < 50 kW		kWh	136,689,934	$0.0061	$833,809
General Service 50 to 999 kW non interval		kW	691,029	$2.4300	$1,679,199
General Service 50 to 999 kW interval		kW	91,471	$2.5777	$235,784
General Service > 1,000 kW		kW	565,225	$2.5777	$1,456,982
Street Lighting		kW	31,343	$1.8325	$57,436
Sentinel Lighting		kW	336	$1.8420	$620
Unmetered Scattered Load		kWh	2,059,067	$0.0061	$12,560
TOTAL					**$6,539,238**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2012**	
Residential		kWh	353,570,085	$0.0049	$1,732,493
General Service < 50 kW		kWh	136,689,934	$0.0046	$628,774
General Service 50 to 999 kW non interval		kW	691,029	$1.7458	$1,206,398
General Service 50 to 999 kW interval		kW	91,471	$1.9295	$176,493
General Service > 1,000 kW		kW	565,225	$1.9295	$1,090,603
Street Lighting		kW	31,343	$1.3496	$42,301
Sentinel Lighting		kW	336	$1.3779	$464
Unmetered Scattered Load		kWh	2,059,067	$0.0046	$9,472
TOTAL					**$4,886,996**

Wholesale Market Service					
Class per Load Forecast				**2012**	
Residential		kWh	353,570,085	$0.0052	$1,838,564
General Service < 50 kW		kWh	136,689,934	$0.0052	$710,788
General Service 50 to 999 kW		kWh	299,190,792	$0.0052	$1,555,792
General Service > 1,000 kW		kWh	189,429,084	$0.0052	$985,031
Street Lighting		kWh	11,559,681	$0.0052	$60,110
Sentinel Lighting		kWh	125,843	$0.0052	$654
Unmetered Scattered Load		kWh	2,059,067	$0.0052	$10,707
TOTAL			**992,624,486**		**$5,161,647**

Rural Rate Assistance					
Class per Load Forecast				**2012**	
Residential		kWh	353,570,085	$0.0011	$388,927
General Service < 50 kW		kWh	136,689,934	$0.0011	$150,359
General Service 50 to 999 kW		kWh	299,190,792	$0.0011	$329,110
General Service > 1,000 kW		kWh	189,429,084	$0.0011	$208,372
Street Lighting		kWh	11,559,681	$0.0011	$12,716
Sentinel Lighting		kWh	125,843	$0.0011	$138
Unmetered Scattered Load		kWh	2,059,067	$0.0011	$2,265
TOTAL			**992,624,486**		**$1,091,887**

	2012
4705-Power Purchased	$79,126,828
4708-Charges-WMS	$5,161,647
4714-Charges-NW	$6,539,238
4716-Charges-CN	$4,886,996
4730-Rural Rate Assistance	$1,091,887
4750-Low Voltage	
TOTAL	**96,806,596**

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2013 Load Foreacst	**kWh**	**kW**	**2011 %RPP**
Residential	335,941,782		90%
General Service < 50 kW	129,942,565		86%
General Service 50 to 999 kW	285,190,036	774,872	16%
General Service > 1,000 kW	181,491,144	562,588	1%
Street Lighting	11,059,201	31,152	0%
Sentinel Lighting	121,120	336	100%
Unmetered Scattered Load	2,002,380		81%
TOTAL	**945,748,229**	**1,368,948**	
	0	0	

Electricity - Commodity RPP	**2013**	**2013 Loss**			
Class per Load Forecast RPP	**Forecasted**	**Factor**		**2013**	
Residential	303,776,890	1.0389	315,583,667	$0.08069	$25,464,446
General Service < 50 kW	111,259,991	1.0389	115,584,289	$0.08069	$9,326,496
General Service 50 to 999 kW	45,786,117	1.0389	47,565,668	$0.08069	$3,838,074
General Service > 1,000 kW	1,776,556	1.0389	1,845,605	$0.08069	$148,922
Street Lighting	0	1.0389	0	$0.08069	$0
Sentinel Lighting	121,120	1.0389	125,828	$0.08069	$10,153
Unmetered Scattered Load	1,621,391	1.0389	1,684,409	$0.08069	$135,915
TOTAL	**464,342,066**		**482,389,465**		**$38,924,006**

Electricity - Commodity Non-RPP	**2013**	**2013 Loss**			
Class per Load Forecast	**Forecasted**	**Factor**		**2013**	
Residential	32,164,891	1.0389	33,415,031	$0.08134	$2,717,979
General Service < 50 kW	18,682,574	1.0389	19,408,702	$0.08134	$1,578,704
General Service 50 to 999 kW	239,403,919	1.0389	248,708,737	$0.08134	$20,229,969
General Service > 1,000 kW	179,714,588	1.0389	186,699,483	$0.08134	$15,186,136
Street Lighting	11,059,201	1.0389	11,489,035	$0.08134	$934,518
Sentinel Lighting	0	1.0389	0	$0.08134	$0
Unmetered Scattered Load	380,989	1.0389	395,797	$0.08134	$32,194
TOTAL	**481,406,163**		**500,116,786**		**$40,679,499**

Transmission - Network		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	348,998,698	$0.0064	$2,233,592
General Service < 50 kW		kWh	134,992,991	$0.0061	$823,457
General Service 50 to 999 kW non interval		kW	684,293	$2.4130	$1,651,198
General Service 50 to 999 kW interval		kW	90,579	$2.5597	$231,855
General Service > 1,000 kW		kW	562,588	$2.5597	$1,440,056
Street Lighting		kW	31,152	$1.8197	$56,687
Sentinel Lighting		kW	336	$1.8291	$615
Unmetered Scattered Load		kWh	2,080,206	$0.0061	$12,689
TOTAL					**$6,450,149**

Transmission - Connection		**Volume**			
Class per Load Forecast		**Metric**		**2013**	
Residential		kWh	348,998,698	$0.0048	$1,675,194
General Service < 50 kW		kWh	134,992,991	$0.0046	$620,968
General Service 50 to 999 kW non interval		kW	684,293	$1.7275	$1,182,116
General Service 50 to 999 kW interval		kW	90,579	$1.9093	$172,943
General Service > 1,000 kW		kW	562,588	$1.9093	$1,074,149
Street Lighting		kW	31,152	$1.3354	$41,600
Sentinel Lighting		kW	336	$1.3635	$459
Unmetered Scattered Load		kWh	2,080,206	$0.0046	$9,569
TOTAL					**$4,776,996**

Wholesale Market Service					
Class per Load Forecast				**2013**	
Residential		kWh	348,998,698	$0.0052	$1,814,793
General Service < 50 kW		kWh	134,992,991	$0.0052	$701,964
General Service 50 to 999 kW		kWh	296,274,405	$0.0052	$1,540,627
General Service > 1,000 kW		kWh	188,545,089	$0.0052	$980,434
Street Lighting		kWh	11,489,035	$0.0052	$59,743
Sentinel Lighting		kWh	125,828	$0.0052	$654
Unmetered Scattered Load		kWh	2,080,206	$0.0052	$10,817
TOTAL			**982,506,251**		**$5,109,033**

Rural Rate Assistance					
Class per Load Forecast				**2013**	
Residential		kWh	348,998,698	$0.0011	$383,899
General Service < 50 kW		kWh	134,992,991	$0.0011	$148,492
General Service 50 to 999 kW		kWh	296,274,405	$0.0011	$325,902
General Service > 1,000 kW		kWh	188,545,089	$0.0011	$207,400
Street Lighting		kWh	11,489,035	$0.0011	$12,638
Sentinel Lighting		kWh	125,828	$0.0011	$138
Unmetered Scattered Load		kWh	2,080,206	$0.0011	$2,288
TOTAL			**982,506,251**		**$1,080,757**

	2013
4705-Power Purchased	$79,603,505
4708-Charges-WMS	$5,109,033
4714-Charges-NW	$6,450,149
4716-Charges-CN	$4,776,996
4730-Rural Rate Assistance	$1,080,757
4750-Low Voltage	
TOTAL	**97,020,440**

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SUMMARY OF CHANGES AS A RESULT OF MODIFYING CAPITALIZATION AND DEPRECIATION POLICY "MODIFIED"CGAAP (MCGAAP)

As previously discussed, Thunder Bay Hydro will be taking the additional year deferral for adoption of International Reporting Standards ("IFRS") to 2014. For the 2013 fiscal year, Thunder Bay Hydro will be amending its capitalization policies and procedures to be more in line with IFRS and refers to this as Modified Canadian Generally Accepted Accounting Principles ("MCGAAP"). The conversion from Canadian Generally Accepted Accounting Principles CGAAP to MCGAAP has resulted in a number of changes to Thunder Bay Hydro's accounting for Plant Property and Equipment (PP&E).

IMPACT ON FIXED ASSETS

Componentization and Amortization

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the item to be depreciated separately. In addition IAS 16 requires that entities perform a review of the assets useful lives, amortization methods and residual values on an annual basis.

Thunder Bay Hydro has reviewed the useful life of its assets with the aid of the Kinetrics report and internal review by the Engineering Department of current asset conditions, construction and maintenance practices. Exhibit 4, Tab 4, Schedule 2 outlines the amortization expense based on the new useful lives of the assets.

Thunder Bay Hydro has restated its continuity statement for the 2013 Test Year to include these changes in Table 2-5.1.

IAS 16 – Property, Plant and Equipment – Measurement after Recognition

For subsequent periods following the initial recognition of an asset, IAS 16 permits the choice of using either the Cost Model or the Revaluation Model for valuing PP&E. Thunder Bay Hydro will continue to use the Cost Model to measure PP&E.

Table 2-5.1 – Fixed Asset Continuity Schedule

Year **2013MCGAAP**

			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)	1,179,533	77,200	-	1,256,733	(986,599)	(51,926)	-	(1,038,525)	218,208
CEC	1612	Land Rights (Formally known as Account 1906)				-				-	-
N/A	1805	Land	133,038			133,038	-			-	133,038
47	1808	Buildings	3,932,848	3,500	(123,959)	3,812,389	(1,862,466)	(72,044)	58,640	(1,875,870)	1,936,518
47	1808	Garage		3,300,000		3,300,000	-	(25,250)		(25,250)	3,274,750
13	1810	Leasehold Improvements	75,507			75,507	(4,450)	(8,399)		(12,849)	62,658
47	1820	Distribution Equipment - ARO	-	45,125		45,125		(7,386)		(7,386)	37,738
47	1820	Distribution Equpment Normally Primary below 50 kV	8,124,042	1,879		8,125,921	(5,875,870)	(319,827)		(6,195,697)	1,930,224
47	1825	Storage Battery Equipment				-				-	-
47	1830	Poles, Towers & Fixtures	33,096,619	3,062,513	(216,435)	35,942,697	(11,352,756)	(725,459)	213,933	(11,864,282)	24,078,415
		Steel Cross Arms	114,893	6,105	(1,274)	119,724	(19,030)	(1,577)	422	(20,185)	99,538
		fibre Glass Cross Arms	10,810	1,274		12,084	(1,274)	(138)		(1,412)	10,672
47	1835	O/H Conductors & Devices - Switches	2,626,249	125,032	(27,097)	2,724,185	(1,574,157)	(57,326)	26,024	(1,605,459)	1,118,726
		O/H Conductors & Devices - Primary & Neutral Cables	26,344,347	2,018,226	(328,450)	28,034,122	(12,740,232)	(325,016)	305,947	(12,759,301)	15,274,821
		O/H Conductors & Devices - Secondary Cables	3,558,642	569,243		4,127,885	(1,348,473)	(50,952)		(1,399,425)	2,728,460
		O/H Conductors & Devices - Reclosures	888,320	144,678		1,032,998	(245,126)	(22,587)		(267,712)	765,286
47	1840	U/G Conduit - Trenches	1,384,431	-		1,384,431	(1,246,119)	(14,463)		(1,260,582)	123,849
		U/G Conduit - Conduits	11,303,081	163,913		11,466,994	(6,495,924)	(73,319)		(6,569,243)	4,897,751
		U/G Conduit - Foundations	1,215,467	42,221		1,257,688	(290,603)	(20,164)		(310,767)	946,921
47	1845	U/G Conductors & Devices - Primary Cables in Duct	11,378,807	465,825		11,844,632	(3,357,579)	(249,042)		(3,606,621)	8,238,011
		U/G Conductors & Devices - Primary Cables Direct Buried	4,878,456			4,878,456	(4,361,795)	(58,711)		(4,420,507)	457,949
		U/G Conductors & Devices - Secondary Cables in Duct	1,076,901			1,076,901	(508,962)	(19,441)		(528,403)	548,498
		U/G Conductors & Devices - Secondary Cables Direct Buried	1,161,140			1,161,140	(1,067,314)	(7,215)		(1,074,529)	86,610
		U/G Conductors & Devices - UG Switchgear	688,012	50,000		738,012	(191,937)	(20,772)		(212,709)	525,303
47	1850	Line Transformers - Vault Combined	914,194	-	(17,024)	897,170	(850,678)	(11,082)	16,128	(845,632)	51,538
		Line Transformers - Enclosure Combined	397,326		(21,896)	375,430	(338,715)	(5,522)	20,745	(323,492)	51,938
		Line Transformers - Pole Top Combined	16,253,446	1,132,505	(243,541)	17,142,410	(8,526,769)	(332,130)	167,194	(8,691,705)	8,450,704
		Line Transformers - Pad MountTransformer Single Phase	5,530,618		(5,460)	5,525,158	(3,208,301)	(105,096)	5,179	(3,308,219)	2,216,939
		Line Transformers - Pad Mount Transformer 3 Phase	5,244,150		(85,722)	5,158,427	(3,021,786)	(94,510)	54,556	(3,061,739)	2,096,688
47	2320	ARO	161,743			161,743	(79,665)	(9,752)		(89,417)	72,326
47	1855	Services (O/H & U/G) - O/H Conductors	8,713,317	508,923	(112,593)	9,109,647	(4,844,203)	(100,688)	139,045	(4,805,846)	4,303,801
		Services (O/H & U/G) - U/G in Duct	7,442,413	253,088	(31,895)	7,663,606	(5,035,981)	(104,356)		(5,140,337)	2,523,269
		Services (O/H & U/G) -U/G Direct Buried	4,714,182			4,714,182	(4,436,160)	(34,772)		(4,470,932)	243,250
47	1860	Meters - Industrial/Commercial Energy Meters	98,013	-		98,013	(68,516)	(2,254)		(70,770)	27,243
		Meters - CT & PT	367,615			367,615	(260,486)	(4,314)		(264,800)	102,815
		Meters - Primary	727,044	25,000		752,044	(509,240)	(8,369)		(517,609)	234,435
										-	-
47	1860	Meters (Smart Meters) - Phase 1	5,829,831	118,374		5,948,205	(1,345,678)	(391,533)		(1,737,211)	4,210,994
		Meters (Smart Meters) - Phase 2	560,165			560,165	(136,029)	(37,319)		(173,349)	386,817
		Meters (Smart Meters) - Phase 3	1,227,479			1,227,479	(249,823)	(81,630)		(331,453)	896,026
		Meters (Smart Meters) - Repeaters Data Coll	402,195			402,195	(90,124)	(26,756)		(116,879)	285,316
N/A	1905	Land				-				-	-
47	1908	Buildings & Fixtures				-				-	-
13	1910	Leasehold Improvements				-				-	-
8	1915	Office Furniture & Equipment (10 years)	1,420,039	36,050		1,456,089	(1,170,147)	(42,182)		(1,212,329)	243,760
8	1915	Office Furniture & Equipment (5 years)	-	-		-	-	-		-	-
10	1920	Computer Equipment - Hardware	2,955,562	81,600	(44,200)	2,992,962	(2,643,350)	(182,002)	37,880	(2,787,472)	205,490
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				-				-	-
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	-			-				-	-
10	1930	Transportation Equipment - Trailers	473,519	-	-	473,519	(473,519)	0	-	(473,519)	0
10	1930	Transportation Equipment - Buckets and Heavy Equipment	4,837,014	825,345	(181,812)	5,480,547	(3,200,025)	(191,875)	181,812	(3,210,088)	2,270,459
10	1930	Transportation Equipment - Light Vehicles	1,233,315	135,000	(181,698)	1,186,617	(851,488)	(37,358)	181,698	(707,147)	479,470
8	1935	Stores Equipment	63,417			63,417	(63,417)	-		(63,417)	(0)
8	1940	Tools, Shop & Garage Equipment	2,516,457	73,700		2,590,157	(2,269,560)	(69,194)		(2,338,753)	251,404
8	1945	Measurement & Testing Equipment	294,334	22,940		317,274	(157,411)	(25,371)		(182,782)	134,493
8	1950	Power Operated Equipment	194,622	13,400		208,022	(59,485)	(20,758)		(80,243)	127,779
8	1955	Communications Equipment	240,489	104,756		345,245	(162,456)	(9,446)		(171,902)	173,343
8	1955	Communication Equipment (Smart Meters)				-				-	-
8	1960	Miscellaneous Equipment				-				-	-
47	1975	Load Management Controls Utility Premises				-				-	-
47	1980	System Supervisor Equipment	566,626	-		566,626	(378,896)	(34,343)		(413,239)	153,387
47	1985	Miscellaneous Fixed Assets	-			-				-	-
	2440	Deferred Revenue		(989,985)		(989,985)		12,712		12,712	(977,272)
47	1995	Contributions & Grants	(17,725,330)	-		(17,725,330)	3,735,983	456,959		4,192,942	(13,532,388)
47	1996	Hydro One Current & Voltage Transformer	1,272,321	-		1,272,321	(137,026)	(42,411)		(179,437)	1,092,884
WIP		Work in Process	1,268,794	(285,238)		983,556	-	-		-	983,556
		Total	**171,366,052**	**12,132,192**	**(1,623,058)**	**181,875,185**	**(94,363,618)**	**(3,666,366)**	**1,409,204**	**(96,620,781)**	**85,254,405**

Amortization allocation to other t/b accounts and o/h	431,835
Hydro One Current & Voltage Transformer posted to separate account	42,411
Gov't assistance directly credited to income 4245	(12,712)
	(3,204,832)

IMPACT ON CAPITALIZATION OF BURDENS

Standard IAS 16 – PP&E states that the cost of an item of PP&E includes 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 allowed for the capitalization of general and administrative overhead, IFRS does not.

Thunder Bay Hydro has reviewed the overhead department to assess which of the costs currently allocated between OM&A and capital would continue to be appropriate expenses to capitalize and which should be removed from the burden and directly expensed as part of OM&A. This analysis was reviewed by external consultants.

For 2013 Thunder Bay Hydro has identified a total of $1,637,952 that was contained in its burden rates and included as capital expense as part of the 2013 capital budget as described in Exhibit 2, Tab 3, as well as amounts reported in the GEA projects of $19,694. The capital budget and GEA projects for the 2013 Test Year has been restated below in Tab 5, Schedule 3, Table 2-5.2 with the removal of these amounts. Table 2-5.3 contains information by account and 2-5.4 shows Thunder Bay Hydro's Burden Rates Capitalized.

OTHER IMPACTS ON CAPITAL

Standard IAS 16 – PP&E states that the cost of an item of PP&E also includes the initial estimate of the costs of dismantling and removing the item and restoring the site. Thunder Bay Hydro has determined that a constructive obligation exists with respect to the plan for the decommissioning of the substations. The constructive obligation relating to the unamortized costs of stations scheduled for dismantling have been included in the cost of the asset. This is also referred to as an Asset Retirement Obligation ("ARO"). Thunder Bay Hydro has capitalized $45,125 related to this ARO obligation.

Also included in the cost of PP&E are estimated costs related to capital work completed as a result of accidents and damages. Historically Thunder Bay Hydro recorded the recovery of costs from customers directly as a reduction of the costs of replacements. Per IAS 16 the impaired assets must be removed from the carrying value of the PP&E and the construction of the replacement asset must be capitalized. Any compensation received for the impairment must be recognized as income. Thunder Bay Hydro has capitalized $187,562 related to these expenditures.

Historically as per the Accounting Procedures Handbook (APH), labour and other material costs for the initial installation and setting of meters and transformers were capitalized in the accounts. Such costs on subsequent resetting of these assets were expensed with only the physical meter or transformer itself being capitalized. Per IAS 16 the carrying amount of assets removed must be accounted for as a removal and any subsequent installations of meters and transformers must be capitalized. As a result, Thunder Bay Hydro has capitalized $112, 670 of costs related to such replacements.

Exhibit 4, Tab 4, Schedule 1 provides a detailed breakdown of these expenses and how they will impact OM&A.

Table 2-5.2 Summary of 2013 Capital Spending with reduction to Burden

	2013 Test (CGAAP)	Burden Amount Removed	Additional Charges Capitalized	Change to Contributions	2013 Test (MCGAAP)
Distribution Plant (Net of Contributions)	8,699,368	(1,637,952)	439,781	54,849	7,556,045
General Plant	4,673,491				4,673,491
GEA Requirements (Net of Contributions)	207,587	(19,694)			187,893
Total	13,580,446	(1,657,646)	439,781	54,849	12,417,429
Renewable Connection Capital Deferral Account	415,175	(39,389)			375,786
Total	13,995,621	(1,697,035)	439,781	54,849	12,793,215

Table 2-5.3: 2013 Capital Budget and GEA Plan - MCGAAP

Distribution Plant

Category	Total	Poles (1830)	OH Cond (1835)	Conduit (1840)	UG Conduit (1845)	Trans (1850)	Services (1855)	Meters (1860)	Station Eqiup ARO (1820)
Additions per CGAAP	9,744,205	3,310,242	3,235,206	246,572	604,296	1,240,222	924,516	183,151	-
MCGAAP - Adjustments to overheads etc.	(1,198,175)	(281,686)	(522,706)	(40,438)	(88,471)	(107,717)	(162,505)	(39,777)	45,125
Capital Contributions	(989,985)	(156,077)	(49,810)	(70,867)	(187,736)	(212,632)	(243,906)	(68,957)	0
Total Distribution Plant Expenditures	7,556,045	2,872,479	2,662,690	135,267	328,089	919,873	518,105	74,417	45,125

General Plant

Category	Total	Buildings and Fixtures (1808)	Office Equipment (1915)	Computer Hardware (1920)	Computer Software (1925)	Transportation Equip (1930)	Tools (1940)	Meas & Testing (1945)	Power Operated Equip (1950)	Communication Equip (1955)
Subtotal	4,673,491	3,303,500	36,050	81,600	77,200	960,345	73,700	22,940	13,400	104,756
MCGAAP - Adjustments to overheads etc.	-	-	-	-	-	-	-	-	-	-
Total General Plant Expenditures	4,673,491	3,303,500	36,050	81,600	77,200	960,345	73,700	22,940	13,400	104,756

Renewable Energy

Category	Total	Poles (1830)	OH Cond (1835)	Station Equip (1820)
Subtotal	207,587	45,669	159,842	2,076
MCGAAP - Adjustments to overheads etc.	(19,694)	(4,333)	(15,164)	(197)
Deferred				
Total Renewable Energy Expenditures	187,893	41,336	144,678	1,879

Table 2-5.4: Burden Rates Capitalized

	% Allocated To Capital	
Overhead Departments	CGAAP	MCGAAP
Downtime	66.22%	66.20%
Engineering	75.54%	61.34%
Fleet Maintenance	61.38%	35.32%
Stores	83.89%	26.25%
Supervisory	60.95%	29.98%

IMPACT ON RATE BASE

Table 2-5.5 below provides a comparison of rate base between CGAAP and MCGAAP for the 2013 Test Year. The change in net book value has been described above. The working capital allowance has increased under MCGAAP as a result of increased operating expenses, stemming from the removal of expenses from capitalized burdens to OM&A.

Table 2-5.5 2013 Test CGAAP vs 2013 Test MCGAAP

Description	2013 Test (CGAAP)	2013 Test (MCGAAP)
Gross Fixed Assets	184,224,014	181,875,185
Accumulated Depreciation	100,265,561	96,620,781
Net Book Value	83,958,453	85,254,405
Average Net Book Value	79,307,055	79,906,174
Working Capital	110,174,865	111,439,285
Working Capital Allowance (13%)	14,322,732	14,487,107
Rate Base	93,629,788	94,393,281

A detailed calculation of the Working Capital Allowance is provided below in Table 2-5.6.

Table 2-5.6

	2013 Test
Distribution Expenses - Operation	3,559,704
Distribution Expenses - Maintenance	3,951,962
Billing and Collecting	2,134,694
Community Relations	141,862
Administrative & General Expenses	4,894,193
Less: Amortization included above	(263,569)
Total Operating Expenses for Working Capital Allowance	14,418,846
Power Supply Expenses	97,020,439
Total Working Capital Expenses	111,439,285
Working Capital Allowance	14,487,107
Working Capital Allowance %	13%

GREEN ENERGY ACT PLAN – Capital Expenditures

Thunder Bay Hydro has submitted a basic Green Energy Act Plan to the OPA and has provided a copy in Appendix 2-B. The OPA provided a Letter of Comment which has been provided in Appendix 2-C. As part of its plan, Thunder Bay Hydro has estimated gross capital spending requirements of $375,786 (revised) in 2012 and $563,679 (revised) in 2013. Thunder Bay Hydro has forecasted strictly capital investment costs and has not identified any O&M costs under the GEA Plan, and as a result, the funding adder calculation discussed in Exhibit 9 is strictly for the capital investment of the 6 FIT reclosers. Please refer to Exhibit 9 for details.

APPENDICES

APPENDIX 2-A

Asset Management Plan

Thunder Bay Hydro Electricity Distribution Inc.

Asset Management Plan

2012-11-02

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SECTION 0: INTRODUCTION

THUNDER BAY HYDRO'S ASSET MANAGEMENT POLICY

Thunder Bay Hydro Electricity Distribution Inc. (TBHEDI) provides electricity to the residents and businesses within the defined city limits of Thunder Bay, Ontario. In order to meet our customer's service expectations, TBHEDI must effectively manage its electrical distribution assets from procurement, through service life, and into retirement.

Our vision is to be regarded as a provincial leader in infrastructure management and customer satisfaction. To this end, Thunder Bay Hydro's Asset Management Policy is to; construct and maintain a safe, environmentally responsible, sustainable and economical distribution system that reliably delivers high quality electricity to our customers while optimizing our shareholder's long term return on investment. We shall comply with all applicable legal, regulatory, and environmental requirements and will perform all functions with public and employee safety as our first priority.

TBHEDI will achieve the objectives of the Asset Management Policy by applying appropriate asset management systems which facilitate the planning, operation, maintenance, and retirement of assets. These systems will;

- Include facets of leading asset management practices;
- Establish long-term asset management strategies and asset objectives which are consistent with the priorities of the corporation;
- Monitor and trend the delivery of the asset management objectives and targets while reviewing the achievement of their intended benefits;
- Incorporate regular audits and formal management reviews designed to seek and implement continual improvement.

Further, all asset management initiatives implemented by TBHEDI to practically fulfill the intentions of the Asset Management Policy shall subject the prioritization of their projects and activities to the degree with which the following objectives are satisfied:

1) Ensuring the health and safety of the public and the TBHEDI employee;

2) Mitigating existing or future introduction of environmental threats;

3) Compliance with regulatory and legal obligations;

4) Fulfillment of customer demand work;

5) Retirement of assets which have reached the end of their useful life; and

6) Improvement of operational efficiency.

THUNDER BAY HYDRO'S ASSET MANAGEMENT INITIATIVES

The following initiatives combine to form TBHEDI's Asset Management Plan. These initiatives are complimentary to one another, often fulfilling, in whole or in part, the objectives of a parallel activity. In no particular order, the TBHEDI asset management initiatives are:

- Asset Condition Assessment;
- Forestry Management Program;
- PCB Management Program;
- Underground Asset Renewal;
- 12kV Distribution Station Refurbishment;
- Above Ground Asset Renewal;
- Voltage Conversion of 4kV to 25kV;

The Asset Condition Assessment is the primary means by which TBHEDI is able to prioritize future capital and maintenance efforts. This assessment fulfills TBHEDI's obligations as set out in the Distribution System Code (the "Code"), monitors the effectiveness of past maintenance and capital activities, targets the efforts of the maintenance regime, and benchmarks the objectives of the long term capital replacement programs.

The Forestry Management Program monitors and manages the approximately 869km of thoroughfare occupied by TBHEDI distribution lines for vegetation encroachment. This program is designed to systematically target areas of severe vegetation infiltration while still supporting crews during storm events, maintenance activities, and large scale capital construction.

The PCB Management Program is a legislated initiative in response to the health and environmental risks associated with assets containing specific levels of polychlorinated biphenyls (PCBs). This prioritized program targets the removal of select quantities of PCB contaminated assets that are in excess of 50 parts per million (ppm) PCB annually, with an ultimate goal of having all >50 ppm PCB assets removed from service by 2020.

The Underground Asset renewal, 12kV Substation Refurbishment, and Above Ground Asset Renewal initiatives are direct outputs of the Asset Condition Assessment. Specifically, these programs target the systematic replacement of assets which are at or near the end of their useful lives. Typically, these replacements are refurbishment to present levels of construction practice and technology.

The conversion of the 4kV sub-network to 25kV acts as a sub-initiative to the Above Ground Asset Renewal and the Underground Asset Renewal Programs. The conversion initiative satisfies the need to replace ageing assets (distribution infrastructure and substations) while providing a standardized urban voltage and reducing distribution system losses.

SECTION 1: TBHEDI ASSET CONDITION ASSESSMENT

ASSET CONDITION ASSESSMENT OBJECTIVES

The Asset Condition Assessment pertains to the categorical evaluation of the TBHEDI distribution assets by qualified TBHEDI staff[1]. This assessment is primarily undertaken for the purposes of risk management and hazard mitigation. The Asset Condition Assessment is an essential driver for TBHEDI decisions on maintenance levels, maintenance requirements, and decisions regarding the selection and scope of capital projects. Ultimately, the objective of this assessment is to monitor physical indicators of asset degradation or malfunction, correlate these observations to distribution system reliability statistics and maintain or replace these assets in a timely and economical fashion. Performance of the Asset Condition Assessment in this manner satisfies the following TBHEDI asset management objectives:

- Ensuring the health and safety of the public and the TBHEDI employee;
- Mitigation of existing or potential environmental threats;
- Compliance with regulatory and legal obligations;
- Informing those programs which retire end of life assets; and,
- Informing those programs dedicated to the improvement of operational efficiency.

For the purposes of manageability and to account for the disparity among assets, the execution of the Asset Condition Assessment has been subdivided as follows:

- Overhead Inspection and Risk Assessment
- Underground Inspection and Risk Assessment
- Substation Inspection and Risk Assessment

---

[1] Internally referred to as the WHOLE risk assessment representing; Workplace specific, Health and safety, Operational, Legislative, and Environmental.

The Overhead Inspection and Risk Assessment encompasses TBHEDI's inspection methods pertaining to the following assets:

- Utility poles and associated framing (framing includes wood and steel cross arms, insulators, standoffs, brackets, and guying);
- Overhead distribution lines including primary and secondary circuits;
- Overhead distribution transformers;
- Overhead distribution switches (includes: load break, air break, in-lines, and reclosers).

The Underground Inspection and Risk Assessment encompasses TBHEDI's inspection methods pertaining to the following assets:

- Pad mounted and vault enclosed distribution transformers;
- Pad mounted and vault enclosed switching assets (i.e. switchgear, vac-pacs);
- Underground network conductors.

The Substation Inspection and Risk Assessment encompasses TBHEDI's inspection methods pertaining to the following assets:

- Substation enclosure/yard/building, grounding/bonding and fencing;
- Breakers, reclosers, fusing, switches and switchgear;
- Power transformers;
- Auxiliary station equipment (AC and DC systems, protective relaying, SCADA equipment,remote terminal units, metering, instrument transformers, lightning arrestors, insulators, bus connections, steel structures, foundations, oil containment, ducts / conduits etc.).

OVERHEAD INSPECTION AND RISK ASSESSMENT

As discussed in rate filing EB-2008-0245[2], TBHEDI conducted a complete risk assessment for all overhead lines, underground equipment, cables and substations. This system wide inspection included a primarily visual inspection of all TBHEDI's utility poles and associated components. Since the 2007 inspection, TBHEDI has been methodically narrowing the scope of the inspection in order to inspect each asset with greater scrutiny while still canvassing the entire system in the period legislated within Appendix C of the Distribution System Code[3].

For the purposes of achieving the legislated inspection regime, TBHEDI has subdivided its distribution territory into 594 one kilometre by one kilometre grids, of which 416 contain TBHEDI assets to be inspected. The 416 active grids are further divided by 3 such that 139 grids may be inspected annually. In this manner, TBHEDI conducts a visual inspection of its utility poles, associated components, overhead lines, and distribution transformers once every 3 years. Following the system wide inspection of 2007, TBHEDI has performed 1/3 system inspections in each year from 2008 through 2011.

This first complete 3 year cycle of formal overhead risk assessments has provided TBHEDI planners with vital statistics relevant to immediate maintenance replacement requirements, near term capital replacement requirements, and long term capital programming strategies. TBHEDI has also learned valuable lessons from the completion of this first inspection cycle resulting in methodology changes for future inspections.

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[2] EB-2008-0245 (TBHEDI COS application filed September 5, 2008): "*In 2007, risk assessments were completed for all Thunder Bay Hydro overhead lines, underground equipment, cables and substations. These assessments entailed inspecting each and every asset and performing a written inspection of each asset where the inspection tool allowed the user to evaluate the risk effectively in each specific location".*

[3] Appendix C of the DSC lists minimum requirements for asset inspection cycles in table C-1.

The 2008-2011 overhead risk assessment involved TBHEDI employees visiting and inspecting the entire population of approximately 20,000 poles owned and maintained by TBHEDI. The staff reported findings categorically according to Table 2 on hard copy maps of 1kmx1km grids of the distribution network. The qualified individuals were also required to provide an estimate of each pole's remaining life using the colour scale shown in Table 1. Once the risk assessment findings were recorded on hard copy maps, these documents were forwarded to Asset Management and Engineering for filing. In early 2011, these records were integrated into the TBHEDI Geographical Information System (GIS).

Assessment Rating	Estimated Remaining Life (Years)
Red	0-2
Orange	3-5
Yellow	6-10
Purple	11-20
Blue	20+

Table 1 – 2008-2011 Utility Pole Assessment Rankings

Concern Codes			
Concern Code	**Nature of Concern**	**Concern Code**	**Nature of Concern**
1. General:			
1.1	Public Safety – General	1.6	Worker Safety
1.2	Public Safety Involving Children	1.7	Reliability
1.3	Environmental Hazard	1.8	Operational Issues
1.4	Maintenance Required	1.9	Regulatory Non-Compliance
1.5	Legal Non-Compliance (Municipal)	1.10	Other (Include description)
2. Poles:			
2.1	Broken/Rotten	2.10	Anchor – Guy Guard
2.2	Leaning	2.11	Anchor – Rod Condition
2.3	Crossarms	2.12	Anchor – Guy Breaker
2.4	Insulators	2.13	Riser Pole – Terminators
2.5	Loose Hardware	2.14	Riser Pole – Cables/Guards
2.6	Pins	2.15	Riser Pole – Brackets
2.7	Finished Grade	2.16	Riser Pole – Grounding
2.8	Other	2.17	Riser Pole – Cut-Outs
2.9	Anchor – Tension	2.18	Other (Include description)
3.0 Overhead Conductor (Indicate voltage level associated with concern)			
3.1	Sag	3.7	Main Bus – Open Wire
3.2	Clearance	3.8	Main Bus – Sag
3.3	Fusing (Lack of)	3.9	Services – Triplex
3.4	Broken Strands	3.10	Service – Open Wire
3.5	Trees	3.11	Services – Clearance
3.6	Main Bus – Triplex	3.12	Other (Include description)
4.0 Switches (Excluding load-break)			
4.1	Connections	4.5	Locks
4.2	Alignment	4.6	Visibility of nameplate
4.3	Insulators	4.7	Other (Include description)
4.4	Grounding		
5.0 Transformers			
5.1	Located below secondary	5.7	Cluster-mount (3Ø)
5.2	Oil Leaks	5.8	Reclosers
5.3	Bushing Damage	5.9	Rust
5.4	Arrestors	5.10	PCB
5.5	Brackets	5.11	Other (Include description)
5.6	Cut-Outs		

Table 2 - 2008-2011 Categorized Overhead Asset Concern Codes

Utility Poles and Associated Components

Similar to the foundation of a home, the utility pole (and associated framing/guying system) provides structural support to the whole of the TBHEDI overhead electrical distribution network. As such, the health of the utility pole population is a key indicator of the integrity of the network and the effectiveness with which the network assets are managed.

The vast majority (>99.6%) of TBHEDI's utility poles are standard wood composition. Wood poles have been employed in overhead distribution for more than a century and have proven to be strong, durable, and cost effective over a reasonable service life. The objective of TBHEDI's wood pole management strategy is to maximize the asset's lifespan while making best efforts to avoid pole failure prior to scheduled replacement. This objective is realized through a regimented inspection, maintenance, and replacement strategy based upon the assessed ability of the pole to adequately perform its intended function. The key factors under assessment are; remaining pole strength, the sufficiency of legacy construction methods, the integrity of auxiliary supports, and the age of the asset.

Wood Pole Strength Factors

While for certain assets it may be possible to establish a reliable lifespan degradation mechanism (i.e. the speed of degradation of a cable is, among other factors, a function of the load levels to which the cable is consistently exposed), an objective condition assessment of a wood pole population is much more difficult to achieve. This is primarily due to the organic nature of the material and the absence of any globally accepted industry standard for wood pole strength testing (excluding destructive testing). There are however broadly accepted factors which can be reliably correlated to the remaining strength of a wood pole. These include:

- Pole class;
- Wood species and growth conditions;

- Concentration of knots, and;
- Integrity of outer shell.

Pole Class

The pole class corresponds to the CSA 'Standard for Wood Utility Poles and Reinforcing Stubs'. This standard provides minimum acceptable dimensions for each pole class taking into account pole height and material. Once a pole is classified a designer is able to estimate the ultimate pole strength (in kilo-newton's) and hence the pole's ability to perform its intended function when new. The pole class is typically recorded in a conspicuous location on the pole by the manufacturer.

Wood Species and Growth Conditions

A wood pole is a composite structure formed from longitudinal wood fibres which are compressed and expanded in rings according to the species and its growth pattern. The density of the wood (its strength) is dependent on the concentration of these growth rings. Natural growth in a dense forest is slow and dependant on the soil and the weather cycles, such trees are dense as they usually have many growth rings per inch of circumference. Poles of the same species may have a large variation in initial strength depending on the growth pattern over the years. In fact, managed growth poles could be weaker than the mean of the species by 20% or more when new. The CSA provides a mean fibre stress (a close approximation to the average bending strength – or Modulus of Rupture) for each common species of wood pole. The variations of strength within the species are accounted for with the 'Fibre Stress Coefficient of Variation' and may be as great as a 24% deviation from the mean. The basis for many existing pole testing apparati is to estimate the pole's remaining fibre stress (given in Psi) and then use the test result to derate the ultimate strength accordingly.

Concentration of Knots

Within the wood fibre structure, knots are present where tree branches once grew. Knots are mechanical weak points that can influence the strength of the structure depending on the size and species of wood. The CSA places limitation on the allowable

concentration of knots in a new pole. The influence of knot clusters on strength is accounted for in the CSA strength estimates.

Integrity of Outer Shell

The majority of a wood pole's bending/breaking resistance resides in the outer 4 inches of the radius (the outer shell). While in service, the integrity of the outer shell may become compromised by any one or a combination of the following (refer to Figure 1):

- Pest infiltration (i.e. woodpecker, carpenter ants);
- Scorching by fire;
- Destructive impacts (i.e. auto collision, vandalism); and
- General exposure - in particular moisture.

(a) Woodpecker

(b) Carpenter Ants

(c) Scorching

(d) Vehicular Collision

(e) Shell Rot Caused by Exposure

Figure 1 - Common Wood Pole Damage

A wood pole may decay from the outside in (shell rot), from the inside out (heart rot), or both. The rate at which a pole decays is a function of the wood species, the preservative applied, the method of preservative application, the environment in which the pole is installed, and the degree to which the pole's protective treatment has been compromised. Regardless of the trigger the result is the same – given enough time, decay will reduce the thickness of the pole's sound outer shell which will result in reduced pole strength (refer to Figure 2). The CSA mandates that once the strength of a wood structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced[4]. This means that, in the absence of alternate forms of damage, a wood pole should not be allowed to remain in service once its outer shell has deteriorated to 1-1/4" at any point along its length. The Local Distribution Company's challenge has been and continues to be, how to objectively evaluate the degree to which the wood pole population's strength is degraded.

[4] CSA 22.3 No. 1

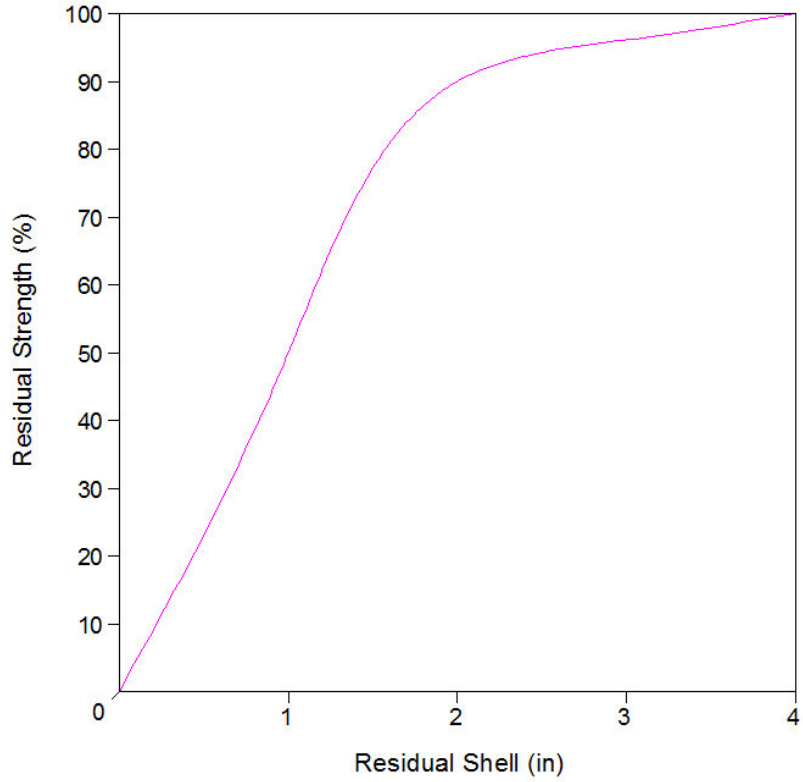

Figure 2 - Pole Strength Vs. Residual Shell Thickness

In addition to traditional methods of sounding[5], probing[6], and visual inspections TBHEDI piloted a testing regime which employed the use of a purposefully designed diagnostic instrument. This testing program took place intermittently from 1999-2005. The

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[5] Sounding refers to rapping a pole from the ground line of the butt up to the extent of the assessor's reach. The assessor is listening to the strike for the hollow thud indicative of a pole with substantial heart rot versus the shortened clunk of a dense, healthy butt.

[6] Probing refers to using a large screwdriver or similar tool to probe areas of localized rot or stab into pole shell suspect of significant heart rot. The objective of this technique is to determine how widespread decay has become or the approximate remaining shell thickness. In general, if a probe easily penetrates through the pole's shell the pole is determined to have no life remaining (in lieu of external bracing).

instrument which was utilized performed a frequency analysis which, when correlated with user inputs, estimated the remaining pole strength in Psi. The user may then compare the estimated strength with the pole's design strength and use these findings to plan for the pole's maintenance, replacement, or follow-up testing. In the opinion of this LDC, the results of this test were at best simply a confirmation of an obviously heavily deteriorated pole's condition, or at worst, an erroneous healthy result from a pole experiencing an uneven distribution of deterioration. As a result of these observations, TBHEDI has returned to sounding, probing, and visual inspections as its primary means of wood pole evaluation.

The execution of the inspection typically involves a single individual performing a street level patrol of the assigned grids over a period of several months each year. The evaluation and subsequent grading of the wood utility poles proceeds as follows:

'Red' poles typically display evidence of one or more of the following;

- Substantial cracking or checking;
- Substantial damage due to vandalism, collision, or pest infiltration;
- Heavy weathering of the pole top; or,
- Substantial deterioration at the ground line.

If a pole is suspected as being 'red' through visual inspection, the pole is then subjected to sounding and probing, thus confirming the degree of degradation. If, upon the closer examination (sounding and probing), the pole is determined to be structurally sound, albeit heavily weathered or scarred, an 'Orange' grade is typically applied.

In keeping with the main objective of this assessment (risk management), the assessor is required by TBHEDI process to submit a concern report for any pole which has been graded red. The pole is then scheduled for replacement. The timing of the replacement is at the discretion of the Power Line Maintenance Supervisor and weighed against the risk of delaying previously submitted concern reports and/or customer driven projects.

When a pole has been graded orange, no immediate replacement is scheduled. This classification is instead referred to as a prioritization index for near term capital projects. Poles of this grade are considered to be of sufficient soundness to continue in service at least until the next scheduled inspection.

Yellow poles are those considered to be approaching end of life (primarily based upon years in service and the appearance of weathering on the pole's outer shell) but yet are estimated to be of sufficient condition to endure a minimum of two more inspection cycles. The yellow pole population provides a predictive element for TBHEDI planners to roughly monitor the approaching demands on the capital construction program. Presently, TBHEDI takes no immediate action on the yellow pole class. However, rot mitigation and butt reinforcement methods are being investigated for their potential to extend the life of qualifying individuals of the yellow pole population.

Purple poles are again, mainly graded as such based on in-service life. The deterioration level of these poles is insignificant. Some consideration is being given to a preservative reinforcement program which may help to increase the lifespan of certain members of this population which may be installed in less than optimal conditions (i.e. significant exposure to moisture at the butt. etc.).

Finally, blue poles show no visual signs of deterioration or damage and are essentially 100% healthy. When new construction or pole replacements take place GIS records are updated to indicate a 'blue' pole has been installed.

Based on the results of the 2008-2011 inspections, the health distribution of TBHEDI's nearly 20,000 poles is estimated as shown in Figure 3.

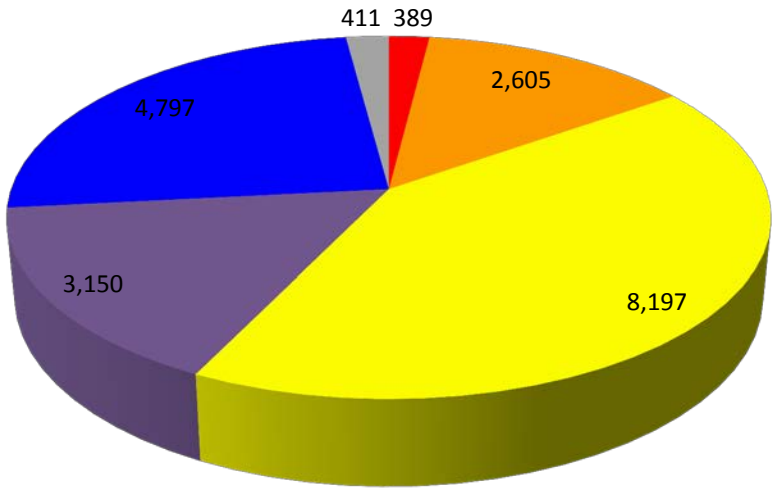

Figure 3 - TBHEDI Pole Health Distribution as at Dec. 2011

Overhead Distribution Lines

Overhead distribution lines refer to the current carrying conductors which distribute power from the transmitter owned transformer stations to the demarcation point between the LDC and the customer.

In general, exposure related degeneration of overhead distribution lines (including corrosion and similar mechanisms) and stress related breakdown (including annealing and straining due to tension) are not the determining factors in a line section's critical path toward end of life.

TBHEDI performs visual inspection which specifically monitors the following symptoms of conductor degeneration:

- Broken strands;
- Strand abrasion;
- Elongation;
- Burn damage;

- Bird caging (separation of conductor from central core).

TBHEDI is considering the use of thermographic imaging for future inspections of the overhead conductor population.

The approximate age distribution of the 2,088 km of primary overhead conductor[7] is as found in Figure 4.

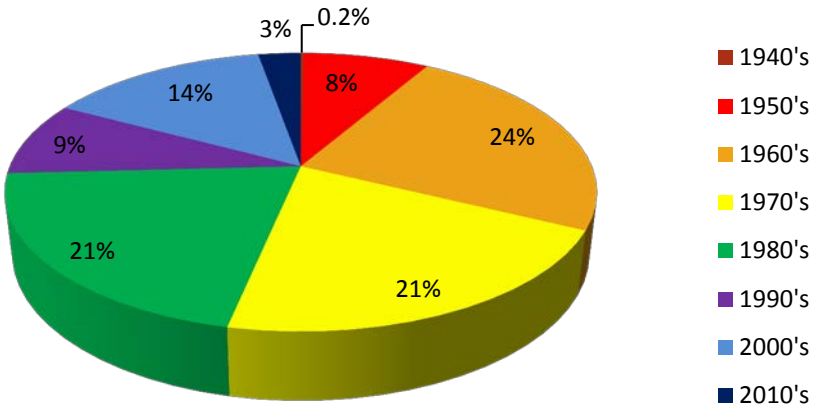

Figure 4 - Approximate Age Distribution of Primary Overhead Conductor by Installation Year

The approximate age distribution of the 2,898 km of secondary conductor[8] (bus and service drops) is as found in Figure 5.

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[7] Length of primary overhead conductor given is defined as circuit length multiplied by number of conductors per circuit.

[8] Length of secondary overhead conductor given is defined as circuit length multiplied by number of conductors per circuit.

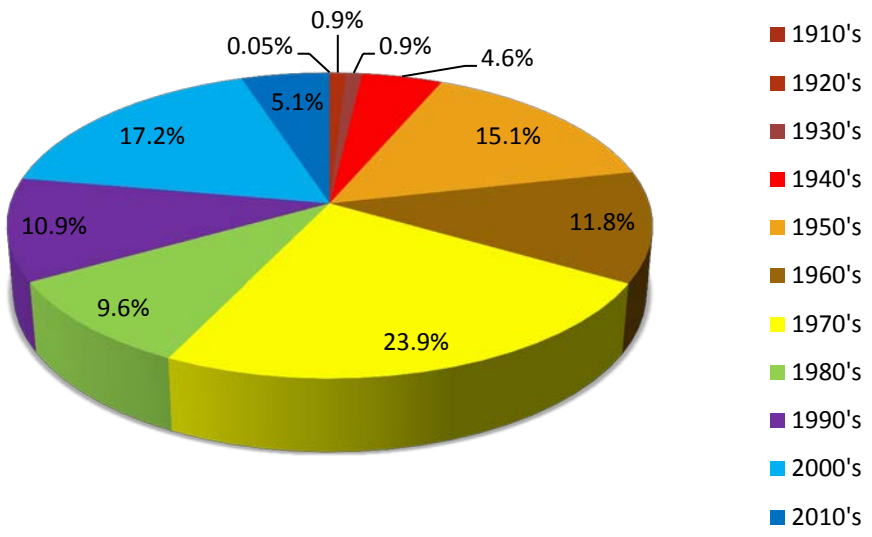


Figure 5 - Approximate Age Distribution of Secondary Overhead Conductor by Installation Year

TBHEDI currently employs no formal strategy targeting the replacement of degraded overhead conductors. The elimination of some older vintage, small diameter conductor (restricted conductor) is however a parallel objective of the overhead renewal and 4kV conversion initiatives.

Restricted Conductor

TBHEDI is aware of a number of incidents in which high voltage electrical wires have broken with no apparent outside cause. The conductors involved in these incidents were No. 4 ACSR and No. 6 copper conductors, hereinafter referred to as “restricted conductors”.

Many of the installations at which the restricted conductors have been identified are 40 years old or more. The age of these conductors in combination with corrosion, tree contacts, over tensioning, small strand size used in long spans, poor quality control in original production, and weakening caused by past faults are all contributing factors to their spontaneous failure.

Identification and recording of TBHEDI's restricted conductor population has been added to the overhead inspection regime. Inspection results are made available to 3rd party tenants and referred to as a prioritization index in the planning of capital replacement projects.

The distribution of restricted conductor in the TBHEDI territory as at December, 2011 is as found in Figure 6.

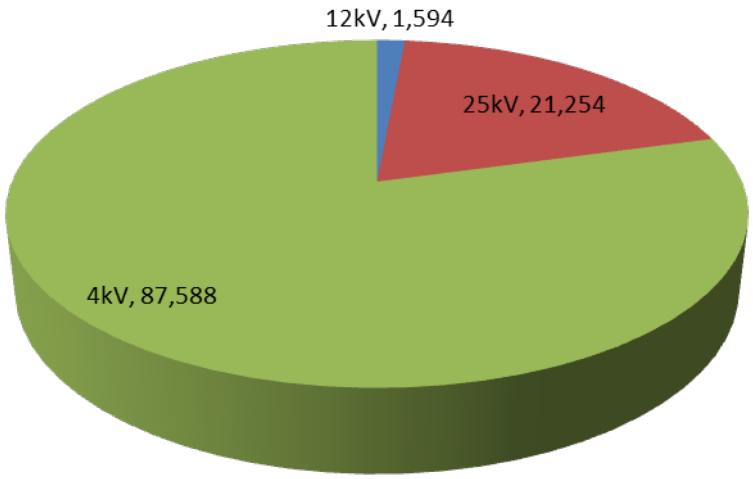


Figure 6 - Restricted Conductor (Quantity[9] in meters by Voltage Class)

Overhead Distribution Transformers

TBHEDI owns and operates approximately 5,000 overhead distribution transformers which step down the primary voltage (25kV, 12kV, and 4kV) to the customer's desired service level voltage.

[9] Restricted conductor quantity is given as circuit length multiplied by number of conductors in circuit.

External indicators of degradation monitored and maintained by TBHEDI as a part of the overhead inspection cycle are:

- External rust buildup;
- Bushing damage; and,
- Tank staining (indicating weaping).

Due to the low complexity, relatively low cost, and somewhat limited customer impact cluster, TBHEDI presently employs a ‘run to failure’ approach with this asset class. The PCB management program and voltage conversion program do however provide mechanisms for the replacement of some of the most heavily aged overhead distribution transformers in the TBHEDI system.

Recently, the TBHEDI GIS has been enhanced to enable coupling of smart meter data to the respective distribution transformer. Future evaluations of transformer health and failure rates will attempt to correlate customer load profiles with the potential for asset failure, paving the way for a low cost, high impact preventative maintenance strategy.

The transformer age distribution amongst primary voltages is as shown in Figure 7. The average installation year of a TBHEDI overhead distribution transformer is 1981.

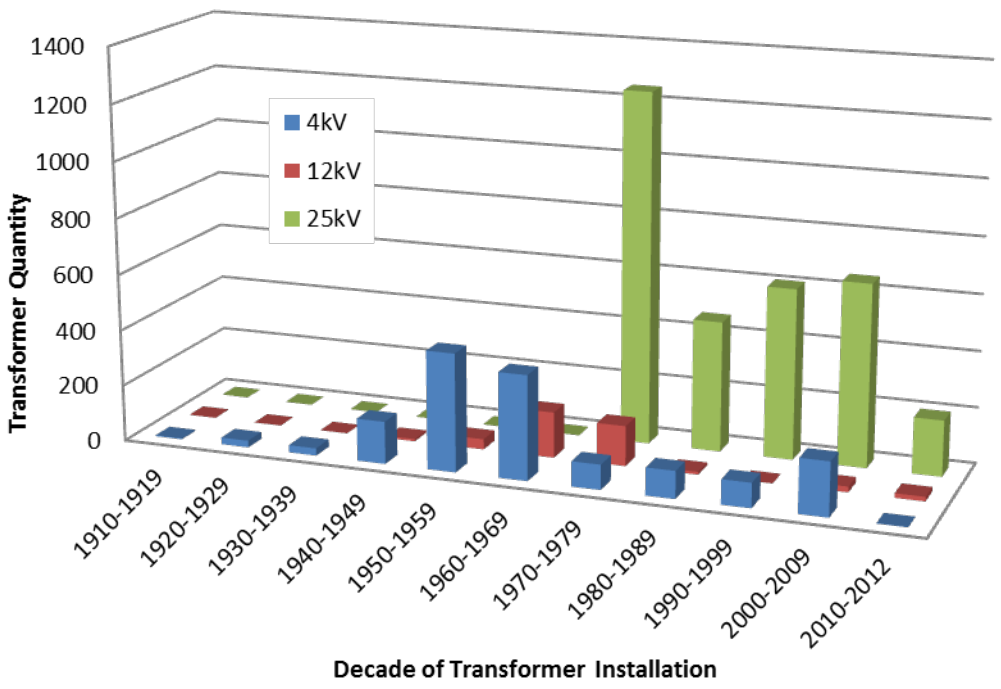


Figure 7 - Overhead Distribution Transformer Age Distribution by Primary Voltage

Overhead Distribution Switches

TBHEDI subdivides the overhead distribution switch asset class as follows:

- Load Break Switch;
- Air Break Switch;
- In-Line Switch; and,
- Recloser.

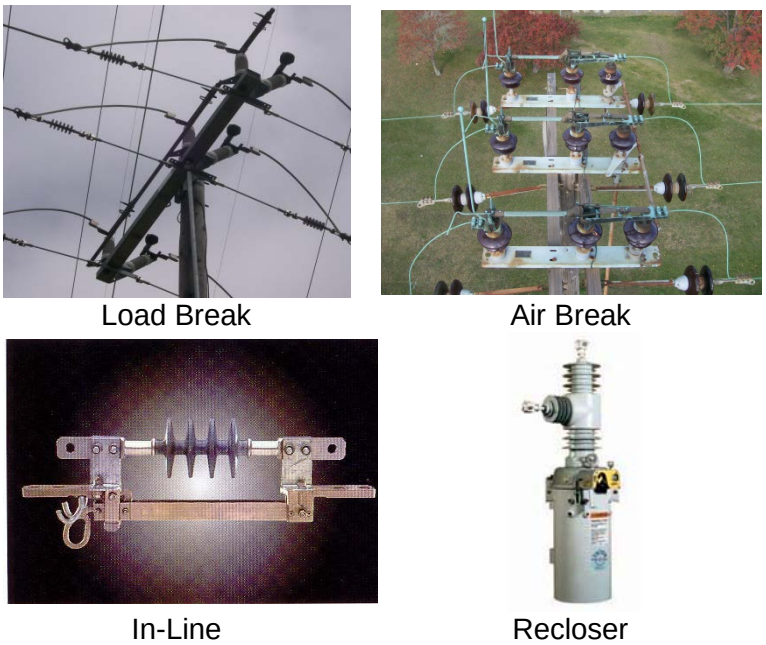


Figure 8 - TBHEDI Overhead Distribution Switch Classes

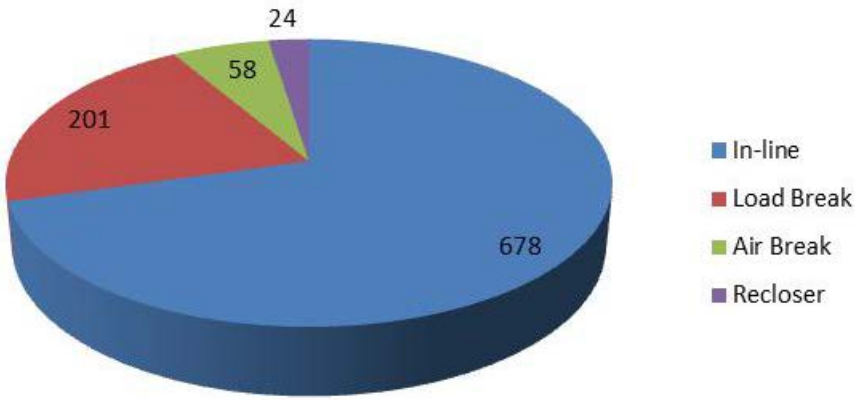


Figure 9 - TBHEDI Overhead Switch Population Distribution

In general, TBHEDI places load break switches at essential network junctions for the purposes of 'hot' switching activities, thereby retaining (or enhancing) customer network connectivity during planned or emergency switching activities.

Air break switches, while not common, are interspersed throughout the TBHEDI network. These switches are designed for non-load breaking switching scenarios. These units are

considered obsolete by TBHEDI and, while no formal program exists, are being removed and replaced with modern load break switches which meet current standards for arc containment.

In-line switches are the least costly of the four switch classes and are typically installed for the purpose of isolation for work protection, and non-load breaking switching scenarios.

TBHEDI has typically deployed reclosers for the purposes of feeder head node protections (on the 12kV network) and remote protections where network impedance does not allow the head node feeder protections adequate visibility into the feeder. Reclosers associated with substations are not included in the switch inspection regime but are rather included as a part of the substation inspection. In general, the TBHEDI recloser population is routinely inspected for visible indications of component wear and soiling. Where the device is not maintainable by field crews, the device is removed from service and returned to the manufacturer for servicing.

TBHEDI conducts a switch inspection regime independent of the overhead risk assessment regime. The switch inspection schedule is divided such that 1/3 of TBHEDI system switches are inspected each year. The independent switch inspection regime is justified by the potential impact felt by the LDC and its customers in the event of a switch failure during a planned switch order, during power restoration activities, and the requirement for TBHEDI personnel to operate (open and close) the asset in order to perform a practical assessment. Critical switch components under inspection are as follows:

- Switch contact condition;
- Arc snuffer condition and contact (where applicable);
- Switch blade alignment;
- Insulator hygiene and condition;
- Conductor connection integrity; and,

- ‘Hot spot’ survey (thermography).

In general, TBHEDI overhead and underground switches are preventatively maintained and are repaired or replaced on an as required basis by maintenance crews.

Legacy Construction Methods

Over the 100+ years of its existence, Thunder Bay’s electrical distribution system has seen much iteration of construction methods, materials, philosophies, and practices. In some cases, what seemed practical or perhaps was the only option at the time, failed unexpectedly/prematurely; causing problems separate from those being mitigated, or simply did not function as intended.

The legacy construction practices found in the overhead component population and of specific concern to Thunder Bay Hydro are;

- Legacy wooden crossarms and pins;
- Pole top lag bolts;
- Poles painted under a rot mitigation program which took place in the 1980’s; and,
- Glass/Porcelain standoff insulators.

Legacy Wooden Crossarm and Pins

In some early installations, wooden crossarms were fitted with wooden dowels which, when inserted into predrilled holes, provided support for the ceramic insulators (Figure 10).

Figure 10 - Wooden Crossarm Pins

Unfortunately, as the pin and crossarm assembly weathers, the friction fit of the pin may weaken thus allowing the pin to move freely (Figure 11).

Figure 11 - Wood Crossarm with Loosened Pin

In the worst cases, the problem of the loosened pin combines with the decay of the wooden crossarm to allow the conductor to roam freely within the pin's axis of rotation. This problem was somewhat addressed by the introduction of steel bolts with oversized washers however in the cases where the cross arm decay is substantial, the problem remains (Figure 12).

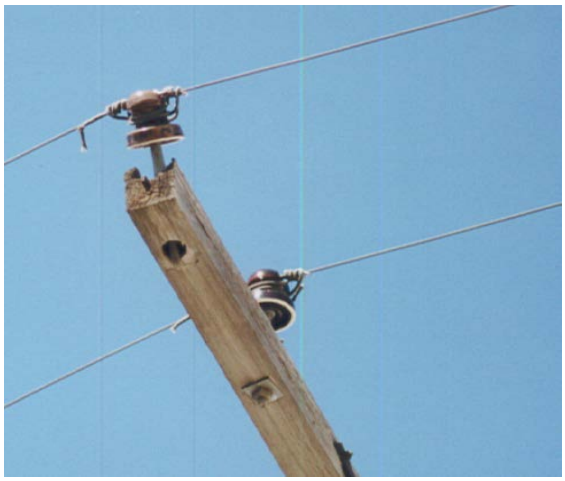


Figure 12 - Decayed Wood Crossarm with Steel Pins

Modern construction has substantially reduced this problem by introducing steel standoffs and steel crossarms (where standoffs are not practical) and limiting the application of new wooden crossarms where practical.

TBHEDI has added the identification of all wood pin construction (regardless of health) to the overhead inspection regiment beginning in 2012. Planners will use this statistic as a prioritization index for future capital replacement efforts.

Pole Top Lag Bolts

In some early installations where a pole was designed to carry a single phase mounted to the top of the pole itself, the connection of the insulator bracket was achieved by lag bolting the top end of the bracket to the pole while through bolting the lower end of the bracket (See Figure 13). The problem with this configuration arises when the pole top becomes substantially decayed. The lag bolt which was initially installed in a sound pole section may become loosened and fall out or have significant play. As a result, the primary single phase conductor may only be held in place by the tension of the adjacent connections and allowed to pivot on the through bolt axis when subjected to lateral forces.

Figure 13 - Pole Top Lag Bolt

TBHEDI added the identification of all pole top lag bolt construction (regardless of health) to the overhead inspection regiment as of 2011. Planners will use this statistic as a prioritization index for future capital replacement efforts.

The known population of this legacy construction method within the TBHEDI system (as at December 2011) is as follows:

Population: 784
Average Age: 50.3 Years

Glass/Porcelain Standoff Insulators

A common fixture in the 12kV and 25kV TBHEDI networks is the standoff bracket which utilizes glass/porcelain insulators (Figure 14). These glass/porcelain insulator components have been known to fail unexpectedly during routine maintenance or seemingly at random while performing parallel activities on a pole equipped with glass/porcelain insulators.

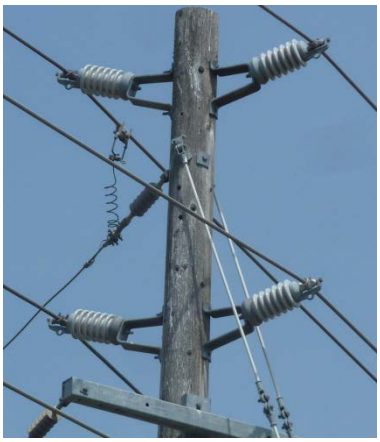


Figure 14 - Standoff with Glass/Porcelain Insulators

Possible causes for the apparent fragility of these components are:

- Electrical flashovers caused by a layer of foreign material accumulation of the surface (i.e. road salt, air borne pollutants, etc.);
- Tensile, torsional, cantilever, vibration, and compression forces which result in fractures in the structure;
- Radial cracks (produced by cement growth) through the glass/porcelain shell; and,
- Separation of the porcelain from the cast mold.

TBHEDI's past and ongoing practice has been to replace these glass/porcelain insulators with polymer equivalents when related work is being performed in proximity. Beginning in 2012, the remaining population of glass/porcelain insulators will be catalogued and mapped. The glass/porcelain insulator statistics will be used as a driver for future maintenance activities.

Painted Poles

For a brief period in the 1980's, a program was implemented with the objective of mitigating pole decay by painting the entire length of the in-service poles. Unfortunately, the remedial pole treatment did not function as intended and in fact has had the opposite effect. The paint acted as a sealant, no longer allowing for the natural transpiration of

moisture from the pole core, to the surface and out to the atmosphere. Consequently, these painted poles retain moisture and accelerate the decay process.

TBHEDI takes no immediate action with respect to the painted pole population however some consideration is being given to collection of the painted pole statistics in order to quantify the effect of the paint on the pole's lifespan.

Review of the 2008-2011 Overhead Inspection Procedures and Findings

Upon input into GIS and analysis of the assessment results on a global scale, TBHEDI has determined the following with respect to existing overhead inspection procedures:

- It is essential to the primary inspection objectives (ensuring health and safety, mitigation of environmental threats, and regulatory compliance) that TBHEDI continue to perform a complete inspection of the overhead distribution assets once every three years.
- The grading scheme employed by TBHEDI for the purposes of estimating remaining pole life (i.e. red, orange, yellow, purple, and blue) provides value where the pole's condition is clearly evident thereby reducing the subjectivity of the assessment (i.e. red, orange, blue). Purple and yellow ratings are however highly subjective in that the assessor does not presently have a set criteria for the grading of these ranges. A revised grading/testing criteria is under development by TBHEDI and will be deployed in the 2012 inspection cycle.
- As TBHEDI continues with future iterations of overhead inspection, the inspection results of previous years will be leveraged to target the efforts of TBHEDI assessment staff. This will result in greater data concentration per asset (i.e. asset age, asset characteristics, localized environmental risks) which will result in greater efficiencies when planning maintenance activities. In order to facilitate this level of data collection, TBHEDI is

investigating the deployment of handheld data consoles for assessment personnel as a supplement to hard copy maps.

- Certain legacy construction practices represent a disproportionate risk to TBHEDI. Elimination of this risk should be targeted in future capital replacement initiatives.

- Presently, TBHEDI's System Control Operators log outage events and their causes in a database separate from the TBHEDI GIS system. This record keeping strategy fulfills regulatory requirements but is however cumbersome with respect to asset specific reliability evaluations. TBHEDI intends to develop an outage tracking feature class in GIS for the purpose of creating an asset specific reliability profile thus enabling planners to enhance the effectiveness of the risk assessment strategy. This system is presently under development and is expected to deploy in early 2013.

- Upon acknowledgement of a certain level of subjectivity within the utility pole grading scheme, TBHEDI performed a blitz data collection[10] of unknown pole ages in the winter of 2011. The purpose of this activity was to determine if a correlation existed between pole condition and the in-service life of the asset. The resulting data provides substantial support for this hypothesis (Table 3 and Figure 15). As such, elimination of aged assets will provide a key metric for the planning of mid to long term capital replacement efforts. (Refer to SECTION 6: ABOVE GROUND ASSET RENEWAL AND

[10] The data contained in GIS, prior to winter of 2011, did not contain an exhaustive record of pole installation dates (particularly those installed prior to 1998). The data collection blitz involved attaching an age estimate to small populations and updating GIS with these age estimates (i.e. if a laneway of 5 poles contains 3 of 1980 vintage, 1 of 1960 vintage and 1 of 1970 vintage then the average age of that laneway is 1974). In this manner, the number of known poles ages increased substantially in a short period of time. Future inspection cycles will target establishment of pole ages on a per asset basis.

VOLTAGE CONVERSION PROGRAM for further details regarding the outcome of this study)

Red	Orange	Yellow	Purple	Blue
49.3	48.0	42.0	33.2	7.0

Table 3 - Weighted Average Pole Age of Classification Group

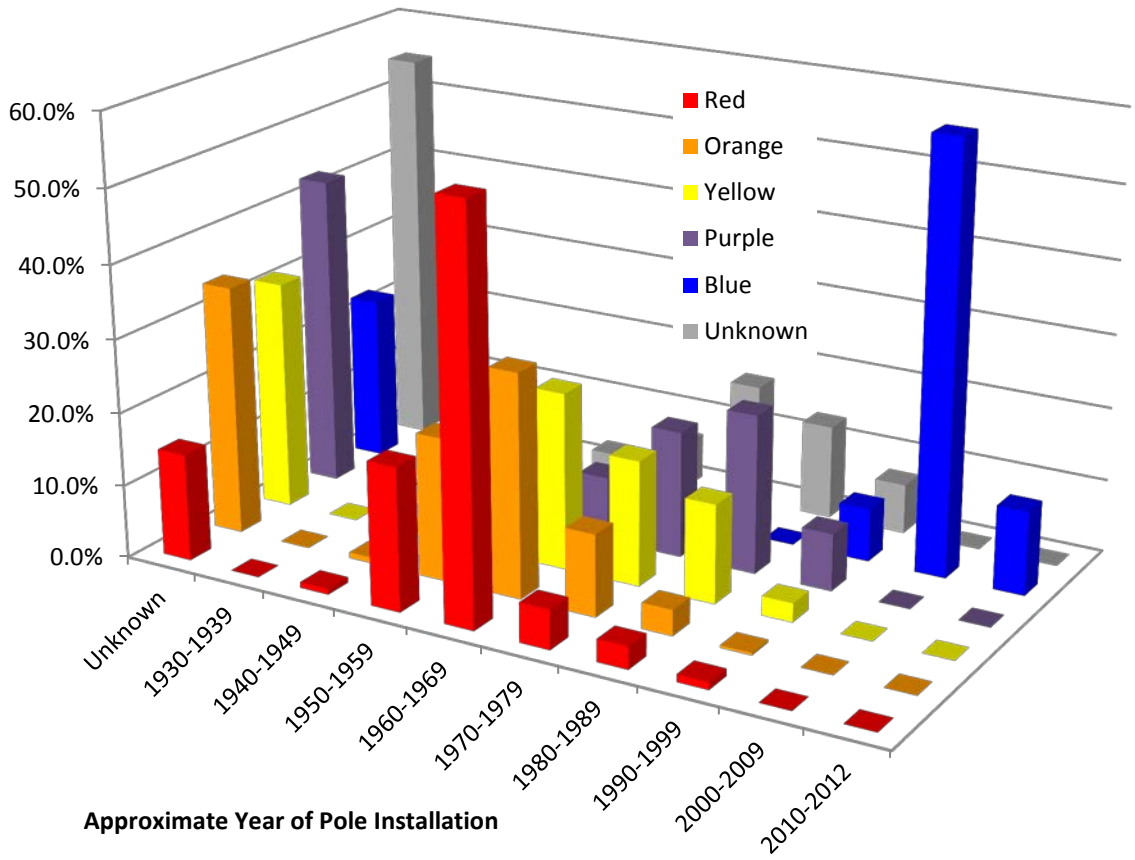


Figure 15 - Age Distribution across Pole Assessment Classes (Normalized by Class)

UNDERGROUND INSPECTION AND RISK ASSESSMENT

The TBHEDI Underground Inspection and Risk Assessment is carried out in a similar fashion to the overhead asset inspection regime. The underground network has been divided geographically into 67 inspection zones which are typically bounded by subdivision development boundaries or industrial/commercial zones. TBHEDI assessment staff, specifically trained in the operation and maintenance of the underground network, inspect 1/3 of the inspection zones per year. Assessment personnel are equipped with hard copy maps of each targeted assessment zone and asked to report findings on these maps and submit them to Asset Management and Engineering for record keeping.

In general, the results of the Underground Inspection and Risk Assessment are used to drive short term maintenance replacements. Presently, with the exception of the two vault enclosed transformers subject to dissolved gas analysis, TBHEDI does not employ a predictive mechanism to anticipate the levels of mid to long term capital underground replacement requirements beyond the correlation of demographic data to the typical useful life of the asset. In 2011 TBHEDI piloted an underground cable testing program for this very purpose however the program was put on hiatus in 2012 for reasons to be discussed later.

Pad Mounted Distribution Transformers & Switching Assets

When inspecting the pad mounted distribution transformer and switching asset population the assessor is asked to monitor and record findings related to the following;

- Enclosure condition (paint and/or rust coverage);
- Condition of operational nomenclature;
- Oil tank integrity (where applicable);
- Ground grid integrity;
- Composition (cement vs. fibreglass) and condition of pedestal;

- Suitability of grade height and slope;
- Concerns related to accessibility by pests and/or unauthorized personnel; and,
- Operational concerns with respect to accessibility, live switching prospects, and vintage/condition of fusing.

Concerns discovered during the assessment are either scheduled for immediate repair or a concern report is filed and the required maintenance is undertaken as the discretion of the Underground & Connections Supervisor.

(a)

(b)

Figure 16 - Pad Mounted Distribution Transformers: (a) Dead front (b) Live Front

TBHEDI owns and operates approximately 2,100 overhead distribution transformers which step down the primary voltage (25kV, 12kV, and 4kV) to the customer's desired service level voltage.

Due to the low complexity, relatively low cost and somewhat limited customer impact cluster, TBHEDI presently employs a 'run to failure' approach with this asset class. The PCB management program and voltage conversion program do however provide mechanisms for the replacement of some of the most heavily aged overhead distribution transformers in the TBHEDI system.

Recently, the TBHEDI GIS has been enhanced to enable coupling of smart meter data to the respective distribution transformer. Future evaluations of transformer health and failure rates will attempt to correlate customer load profiles with the potential for asset failure, paving the way for a low cost, high impact preventative maintenance strategy.

The transformer age distribution amongst primary voltages is as shown in Figure 17. The average installation year of a TBHEDI pad mounted distribution transformer is 1988.

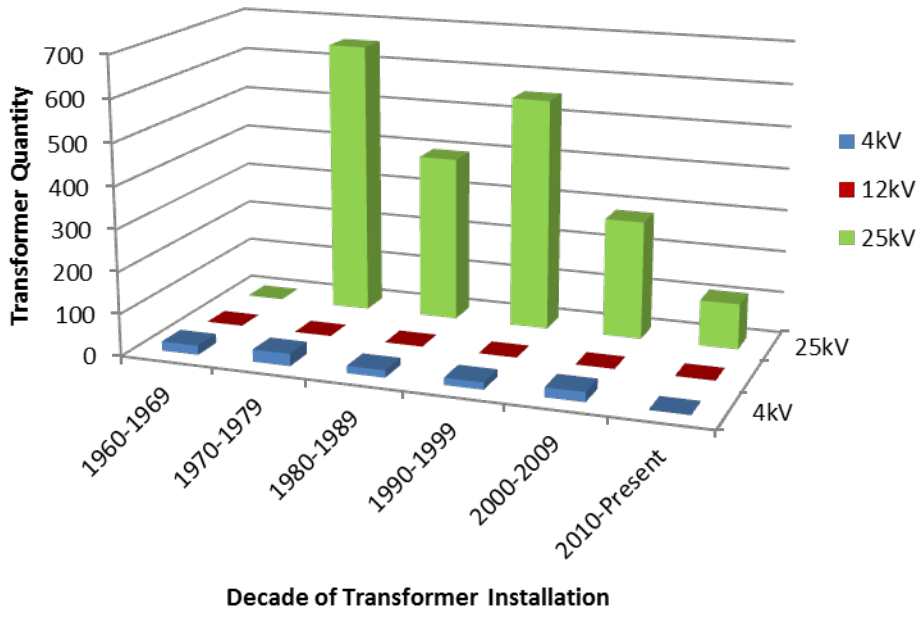


Figure 17 – Pad Mounted Distribution Transformer Age Distribution by Primary Voltage

Vault Enclosed Assets Distribution Transformers & Switching Assets

When inspecting the vault enclosed distribution transformer and switching asset population, the assessor is asked to record;

- Condition of system neutral;
- Presence of oil leakage;

- Proximity of conductive materials to live components;
- Potential for flooding;
- Adequacy of ventilation;
- Adequacy of lighting;
- Accessibility for switching operations;
- Accessibility for asset replacement;
- ‘Hot spot’ detection (thermography); and,
- Overall condition of assets.

In certain cases, where the replacement cost of the asset warrants, monthly, quarterly, bi-annual or annual dissolved gas analysis of transformer oil is performed.

Figure 18 - TBHEDI Vault LC1

TBHEDI tracks and inspects vault enclosed distribution transformers separately from pad mounted distribution transformers due to their inherent complexity and resulting higher capital replacement costs. In certain cases, where capital replacement costs and customer impact due to failure would be substantial, transformers are tested for the presence of moisture in the oil, oil contamination, and dissolved gases associated with internal dielectric breakdown or fault conditions. Dissolved gas accumulation is trended over a period of time to provide planners with guidance when budgeting for the replacement of these units. Due to operational complexities and the costly nature of maintenance/replacement of vaults and their associated assets, TBHEDI prefers to service buildings externally and as such, where possible, end of life vaults are decommissioned and abandoned rather than rebuilt.

The vault enclosed transformer age distribution amongst primary voltages is as shown in Figure 19. The average installation year of a TBHEDI vault enclosed transformer is 1976.

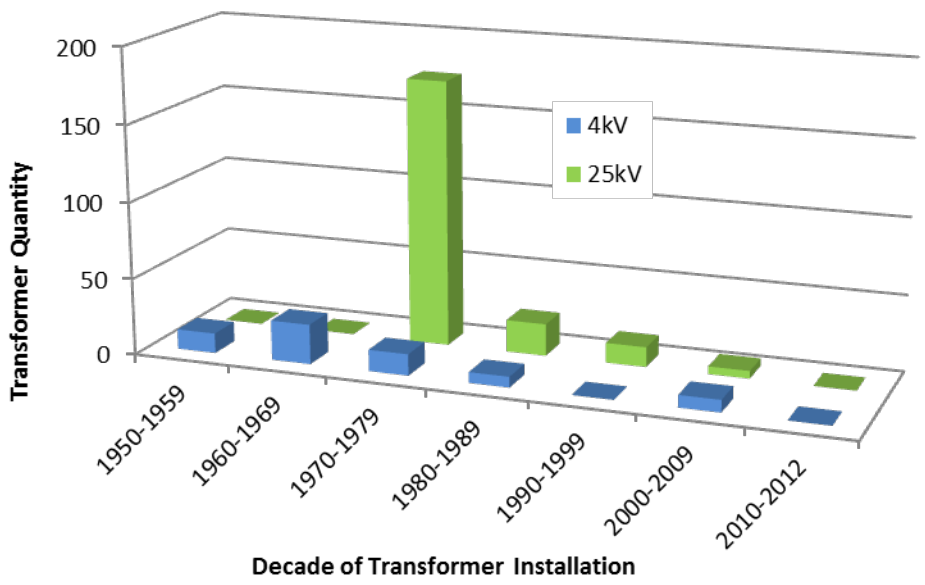


Figure 19 - Vault Enclosed Distribution Transformer Age Distribution by Primary Voltage

The present state of the two vault enclosed[11] distribution transformers subject to dissolved gas analysis is as follows:

Location	Asset Age	Condition	Current Testing Regime	TBHEDI Remediation Actions
Northwood Plaza	41 Years	• Evidence of significantly overheated cellulose insulation • Possible presence of minor fault	Resample every 6 months	Capital replacement of asset to occur within 3-5 years.
Waverly Towers	41 Years	• Evidence of significantly overheated cellulose insulation • Possible presence of fault	Resample in one year	Capital replacement of asset to occur within 3-5 years.

Table 4 - Vault Enclosed Transformers: Dissolved Gas Analysis Results

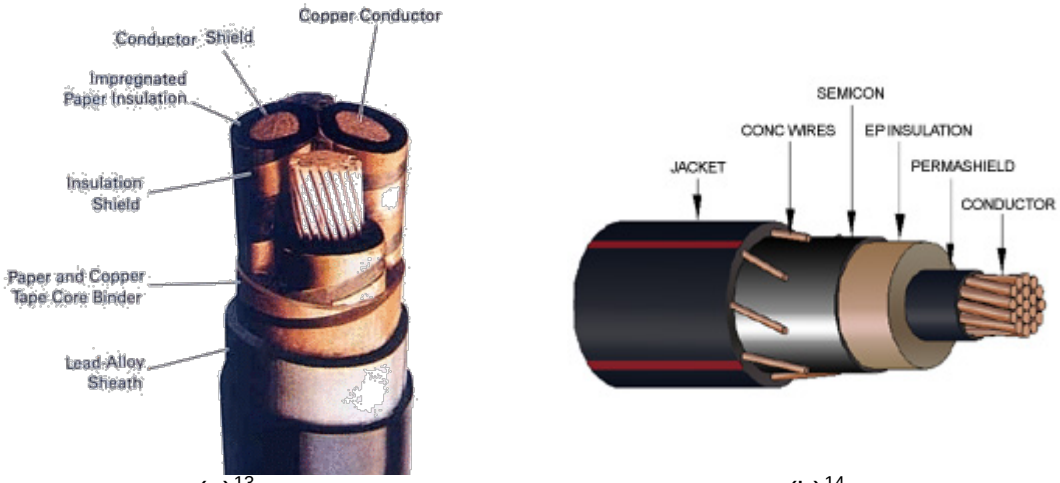
Underground Network Conductors

TBHEDI owns and maintains approximately 416km[12] of primary underground distribution conductors. These conductors are found over the full spectrum of TBHEDI distribution voltage levels, are composed of either copper or aluminum, may be contained within duct or directly buried, and are single conductor cables or combined to form polyphase installations.

[11] Note that although the 'Northwood Plaza' installation is not technically "vault enclosed", its configuration and capacity demand an inspection regime similar to the vault enclosed assets but not to the extent of the substation inspection regime. As such, its inspection results are included in this section.

[12] Conductor quantity is given as circuit length multiplied by number of conductors in circuit

Medium voltage cable designs are quite complex. Whereas all designs include a metallic core conductor insulated from ground by some type of dielectric, many different materials and constructions have been used over the years. A typical cable design includes: the core conductor (copper or aluminum), a semiconducting conductor shield, the insulation (most typically oil impregnated paper or extruded ethylene propylene (EPR) or cross link polyethylene (XLPE)), a semiconducting insulation shield, and a metallic shield (usually lead, copper tape, or copper wires). Cable designs most common in the TBHEDI underground network are paper insulated lead covered (PILC) and cross link polyethylene (XLPE). TBHEDI employs tree retardant cross linked polyethylene insulated cables (TBRXLPE) for all new underground installations (Early 1990's installations and forward).



(a)[13] (b)[14]

Figure 20 - Medium Voltage Cable Designs: (a) PILC (b) XLPE - Concentric Neutral

The failure mechanisms associated with medium voltage cables are categorized as follows:

[13] http://www.otds.co.uk/cables.php

[14] http://www.kerite.com/catalog/catalogfiles/underground_copper_25kv.htm

- mechanical and installation damage;
- operational damage; and,
- age related deterioration.

Mechanical & Installation Damage

Cable system components can be damaged mechanically during handling in the factory, shipment, handling at the warehouse or job site, during installation, and by dig ups or other physical means during operation (i.e. settling of backfill, frost heaves etc.). Such damage can involve cuts, scrapes, excessive sidewall force, and possible intrusion of water into the strands of the core conductor. Cuts, scrapes, and excessive sidewall force may be immediately catastrophic and prevent the cable from being successfully energized, or they may result in damage to the jacket, insulation shield, or outer portion of the insulation.

Once in service, damage to the insulation shield or insulation is likely to produce partial discharge[15] and lead to failure. Damage to the jacket may allow water to permeate the space between the jacket and insulation shield and result in corrosion of the metallic shield (metallic corrosion is of even greater concern in the case of directly buried, unjacketed cable). Corrosion of the metallic shield may lead to leakage current and tracking. Tracking can erode the insulation shield and insulation, eventually leading to significant deformation of the cable's stress gradient and failure of the cable.

Water intrusion into the conductor of a PILC cable may lead to leakage current, localized overheating, and eventual failure. The presence of water in the strands of XLPE or EPR cable may be a problem if internal pressure causes the water to migrate from the cable along the interfaces and exit at a splice or termination. The water may provide a conductive path from the cable core conductor along the interfaces, and exit at the joint

[15] IEEE Standard 400-2001 defines a partial discharge as, "an electrical discharge (formation of streamer or arc) that does not bridge the entire space between two electrodes".

between the outer layer of insulation semiconductor on the cable and the outer layer of semiconductor on the splice or termination. Under these conditions, short circuit and failure are likely to occur.

Physical damage to the lead sheath of PILC cable may allow oil to leak out and/or provide a path for water to enter and be absorbed into the insulation. Loss of oil would likely lead to voids and result in partial discharge upon energization.

Operational Damage

Operational damage can occur when the cable system is exposed to severe load cycling, overloads, or short circuit currents. Load cycling can result in linear expansion and contraction of the cable and can cause work hardening and cracking of the lead sheath or chafing of EPR or XLPE cables. Load cycling may have a more severe impact on splices and terminations because they may be physically restrained and may therefore experience significant compressive or tensile forces. Such forces may cause components within the splice or termination to shift, resulting in voids or gaps at insulating and semiconducting interfaces which could lead to partial discharge. Overloads and short-circuit currents can have similar or even greater effects. They can produce high temperatures that lead to deformation of XLPE and EPR cable materials and result in gaps or voids. In severe cases, this deformation may allow migration of the core conductor within the insulation migration of shield wires into the insulation semiconductor layer or even into the insulation (especially where the cable passes through bends or where there is significant sidewall force caused by pressure from adjacent cables, supports, or restraints). Gaps and voids produce partial discharge. If no gaps or voids are created but the insulation/conductor geometry is changed by overheating, the damage may not lead to partial discharges, but may reduce the dielectric strength of the insulation. In extreme cases, this may lead to localized leakage current. Heat generated by overloads or short circuit currents within PILC cable is likely to produce localized charring, leading to increased leakage current and reduced dielectric strength.

Age-Related Deterioration

Age related deterioration of PILC can result in waxing or depolymerisation of the impregnating oil, migration of the oil (especially away from riser sections and splices), and decomposition of the paper. Such deterioration can result in voids which will produce partial discharge or result in local charring, increased leakage current, and reduced dielectric strength. Age related deterioration of EPR and XLPE cable can result in loss of adhesion between the insulation and the semiconductor insulation screen, leading to gaps or voids at this interface and partial discharge.

The most frequently discussed form of age-related deterioration of EPR and XLPE cables is water treeing[16].

Figure 21 - Water Tree in XLPE Cable (insulator and conductor screen interface)[17]

[16] Water treeing is defined as: moisture permeation of the conductor insulation in the presence of electrical stress (a phenomenon known as dielectrophoresis), identifiable by their branch-like structure at the microscopic level.

[17] General Cable Presentation: Medium Voltage Cables – Life Expectancy

Water trees may take many years to grow sufficiently large and dense to significantly reduce the dielectric strength of the insulation however given sufficient time, well-developed water trees may be converted into electrical trees[18] (especially if accelerated by lightning or other over voltages) and produce partial discharge. It should be noted that water trees will also reduce the cable's dielectric strength of insulation and impulse withstand capability. Finally, exposure related corrosion of the metallic shield of EPR and XLPE cables can lead to problems similar to those discussed previously.

[18] IEEE 400.2 (2004), clause 3.1.5, defines electrical trees as "Tree-like growths, consisting of nonsolid or carbonized microchannels that can occur at stress enhancements such as protrusions, contaminants, voids, or water trees subjected to electrical stress for extended time periods. At the site of an electrical tree the insulation is damaged irreversibly, partial discharge may be present, and complete insulation breakdown may be only a question of time."

TBHEDI Underground Partial Discharge Cable Testing Program

In 2011 TBHEDI piloted a underground cable testing program in an effort to determine the health of the most critical underground conductors in the distribution network. Testing was performed in partnership with a 3rd party which applied industry standard practices for the detection of partial discharges. The 2011 testing was isolated to the 30 cables (ten three phase circuits) which originated from the 25kV, Fort William Transformer Station. Failure of any one of these cables represents a significant risk to TBHEDI given that each supports the entire feeder to which it is associated. The results of the 2011 testing are as shown in Table 5 and Figure 22.

Total Number of Conductor Sections Tested:	30
Total Number of Terminators Tested	60
Total Length of Conductor Tested	4,650m
% of Conductors Experiencing Critical Partial Discharge	17.9% (832m)
% of Terminators Experiencing Critical Partial Discharge	16.7% (10 units)

Table 5 - 2011 TBHEDI Partial Discharge Testing Results

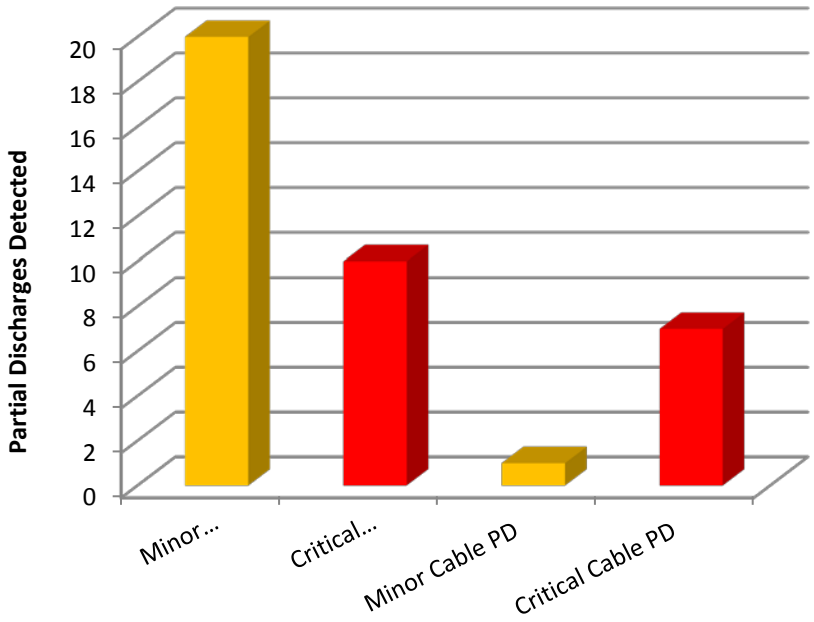


Figure 22 - 2011 Partial Discharge Detections

TBHEDI is continuing to respond to the findings of the 2011 report having experienced significant lead times with respect to the procurement of the appropriate 1250 MCM replacement cable.

Upon review of the 2011 testing activities, TBHEDI determined the pilot to be a success and began planning for the development and execution of a long term (10 year) testing regime with the intention of generating an overall underground distribution cable health profile. This health profile would then become a key input for the planning of short term maintenance and mid to long term capital replacement of underground infrastructure.

The 2012 cable testing strategy was designed to target the most critical arterial underground cables in the TBHEDI network. Priority was first established by multiplying the connected kVA by the number of customers connected downstream of the cable section, sections were then ranked from highest score to lowest. TBHEDI planners then examined this output to determine the final list of cables to be tested. Testing criteria was based upon; number of available contingencies should the cable fail, anticipated replacement date of the cable based on parallel capital replacement activities, knowledge of historical failures associated with the cable, and approximate age of cable.

The 2012 testing effort was originally intended to take place over 8 days and targeted 30 cable sections (90 conductors) with a total conductor length of approximately 7,400m. Targeted cable sections were largely substation risers and underground sections of express feeders.

Testing began on April 16, 2012 and was suspended on April 19, 2012 following the catastrophic failure of a cable which had been tested and returned to service. This cable failed in such a manner as to cause the failure of five adjacent power cables resulting in a complete shutdown of a TBHEDI 12kV distribution station (Balsam Street Substation) until repairs could be completed. This failure, the detection of critical partial discharge in a crucial river crossing, and the suspicion that testing procedures exacerbated the degradation of the substation cable led TBHEDI to suspend testing early. TBHEDI reasoned that, although a health metric is desired for the underground cable population,

the risk of further failures could not be adequately managed given present resource availability levels. As such, the cable testing program has been suspended in the near term and has been replaced by a systematic replacement program aimed at replacing arterial cables known to be nearing or beyond their typical useful life, subjected to continuous substantial loading, and whose failure would result in significant customer impact.

The results of the 2012 testing are as shown in Table 6 and Figure 23.

Total Number of Conductor Sections Tested:	18
Total Number of Terminators Tested	36
Total Length of Conductor Tested	1,865m
% of Conductors Experiencing Critical Partial Discharge	19.6% (366m)
% of Terminators Experiencing Critical Partial Discharge	19.4% (7 units)

Table 6 - 2012 TBHEDI Partial Discharge Testing Results

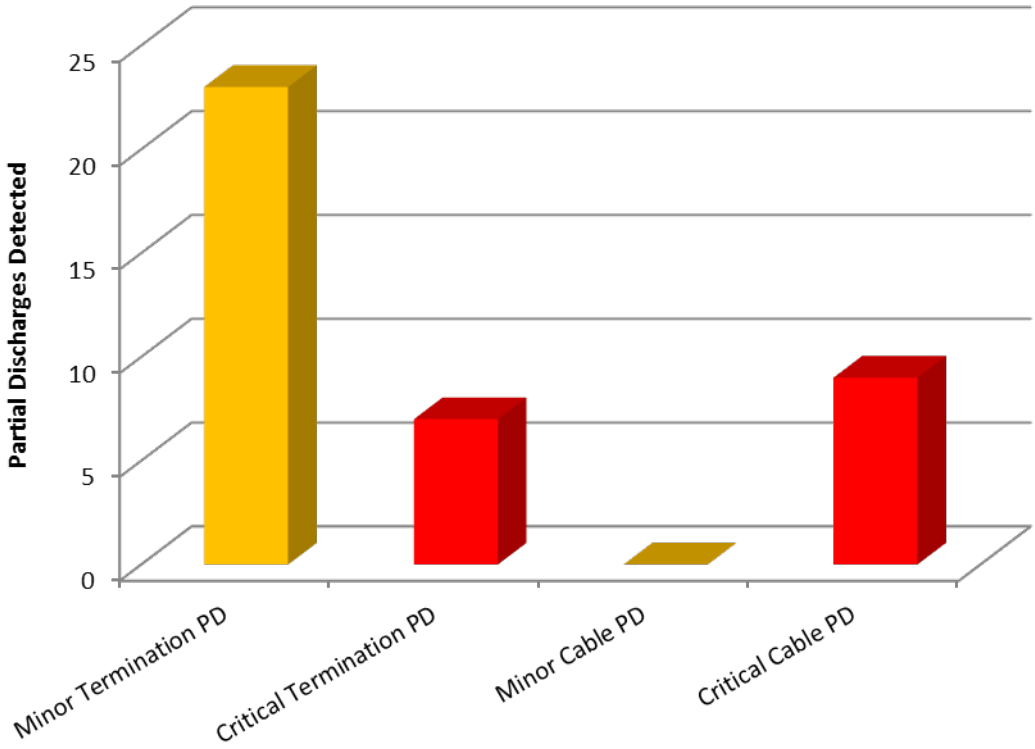


Figure 23 - 2012 Partial Discharge Detections

Approximate TBHEDI underground cable demographics are as found in Figures 24-26.

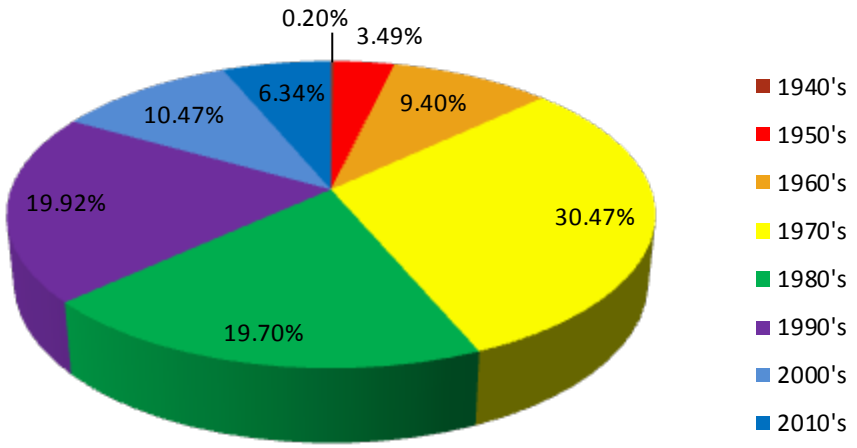


Figure 24 - Approximate Age Distribution of TBHEDI Total Underground Cable Population

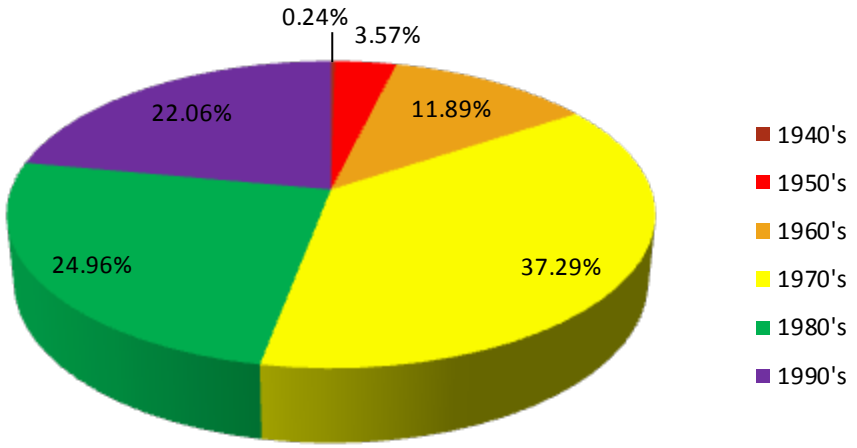


Figure 25 - Approximate Age Distribution of TBHEDI Direct Buried Underground Primary Cable Population

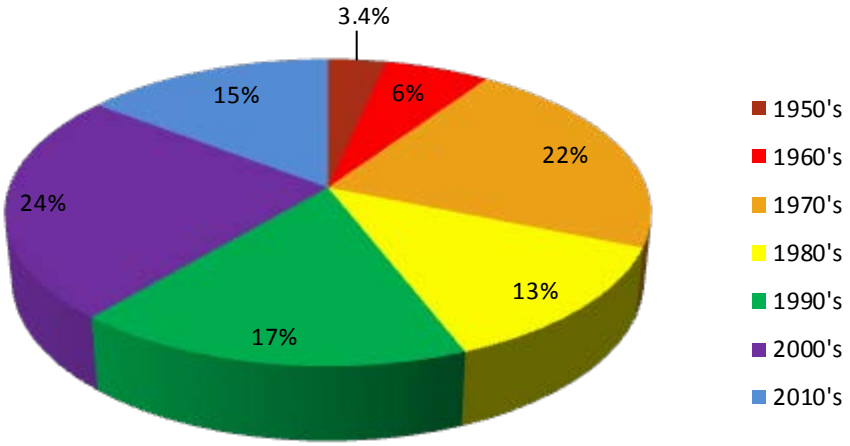


Figure 26 - Approximate Age Distribution of TBHEDI Ducted Underground Primary Cable Population

Review of Underground Inspection Procedures and Findings

The condition assessment of TBHEDI's underground distribution assets is largely based upon the in-service life of the asset with respect to the typical useful life of that asset class. TBHEDI acknowledges the limitation of this approach given that asset replacement based solely on age may cause some assets to be removed prematurely while deferring replacement of others which may be in poorer condition.

It is anticipated that, by leveraging the load profile data now available from the smart meter population (as a supplement to the asset's known installation date), TBHEDI planners will be better equipped to determine asset specific mid to long term capital replacement requirements of the pad mounted transformer population. Deployment of this analysis technique is expected to roll out in the fall of 2012.

The intention of the TBHEDI Cable Testing program was to determine the health of critical TBHEDI underground cables independently of the estimated cable age. Based on the outcome of the 2012 testing, TBHEDI is re-evaluating this approach given the advanced age of many of the high priority cable sections and the apparent elevated risk of failure introduced with the testing procedure (whether it be caused by transient over-voltages on re-energization or by the cable testing itself). In the near term, TBHEDI

planners will target the replacement of heavily aged, arterial underground cables in its capital replacement strategy. Future underground risk assessments will be reviewed for their effectiveness in evaluating the health of heavily aged subdivision networks and modified where necessary. A modified inspection regime is targeted for the 2013 inspection cycle.

Presently, TBHEDI's System Control Operators log outage events and their causes in a database separate from the TBHEDI GIS system. This record keeping strategy fulfills regulatory requirements but is however cumbersome with respect to asset specific reliability evaluations. TBHEDI intends to develop an outage tracking feature class in GIS for the purpose of creating an asset specific reliability profile thus enabling planners to enhance the effectiveness of the risk assessment strategy. This system is presently under development and is expected to deploy in early 2013.

SUBSTATION INSPECTION AND RISK ASSESSMENT

The majority of TBHEDI customers receive primary service at the 25kV voltage level directly from one of the three Hydro One owned transformer stations (58% of all customers). The city's older urban districts (34% of all customers) are serviced at 4kV from fourteen TBHEDI owned distribution stations (DS). Finally, the remaining 8%, primarily rural customers, are serviced at 12kV from four distribution stations also owned and managed by TBHEDI. The following table lists the voltage level and designation of each TS and DS which is owned and operated by TBHEDI:

Designation		Voltage Level
3	Hardisty	4kV
4	Vickers	4kV
5	Donald	4kV
6	McPherson	4kV
7	Mary	4kV
9	Mountdale	4kV
11	High	4kV
12	Camelot	4kV
14	Algoma	4kV
15	Grenville	4kV
16	MacDonnell	4kV
18	Balsam	4kV & 12kV
19	Broadway	12kV
21	Windemere	4kV
22	Brock	4kV
23	Alice	12kV
36	Mapleward	12kV

Table 7 - TBHEDI System Transformer/Distribution Stations

TBHEDI performs a visual inspection of all substations monthly and a detailed inspection of all substations every three years..

Substation Fencing and Enclosure

The substation fence is the primary barrier which restricts unauthorized access to the TBHEDI substation. Maintenance of the integrity of this barrier system is critical for public safety, regulatory compliance, network reliability, and accessibility for TBHEDI

staff. TBHEDI inspects the fence of each distribution station annually. The substation barrier and yard inspection notes the following;

- integrity of continuous bonding conductor connections to all fence sections;
- degree of rusting or corrosion;
- legibility and regulatory compliance of existing signage;
- integrity of gate locks;
- overall barrier integrity and evidence of tampering;
- sufficiency of course aggregate coverage;
- proliferation of weed and grass growth in the station yard (herbicide is applied annually); and,
- condition and suitability of soil grading around power transformer pad.

The substation enclosure may either consist of a small shed which houses sensitive protection and control equipment (typical of station 36, 23, and 19) or a permanent structure which houses protection and control equipment as well as power distribution equipment. Maintenance of the substation enclosure is critical for public safety, regulatory compliance, network reliability, and efficiency of TBHEDI operations. The substation enclosure inspection notes the following;

- integrity of building foundation;
- cleanliness;
- condition of moisture barriers (i.e. roofing); and,
- accessibility (i.e. lighting, stair condition, etc.).

In general, deficiencies noted in the yard, fencing, and substation enclosure are repaired annually on an ‘as needed’ basis.

Substation Power Transformers

TBHEDI classifies substation power transformers as those transformers, owned by TBHEDI, which are located within the substation enclosure and step down the primary, 25kV, network voltage to one of two sub-network distribution voltages (12kV and 4kV).

Figure 27 - McPherson Substation 4MVA Power Transformer (Vintage 1957)

As devices which transfer energy from one electrical circuit to another by electromagnetic coupling without moving parts, power transformers are normally regarded as highly reliable assets because they are designed and constructed using time-proven technology and materials. It is generally believed that transformer design was already mature at the turn of the 20th century with few changes to the essential components having taken place since that time.

The principles that govern the function of all electrical transformers are the same regardless of size or application. The typical power transformer is submerged in mineral

oil for insulation and cooling and is sealed in an airtight metallic tank. Low and high voltage conductors lead to and from the coils through bushings. Inside the transformer tank, core and coils are packed close together to minimize electrical losses and material costs. The mineral oil coolant circulates by convection through external radiators.

The performance of power transformers depends on dielectric insulation and cooling systems. These two systems are intimately related; it is the amount of heat that both the core and the winding conductors generate that determines the permanence and durability of the insulation, while it is the dielectric insulation system that is designed to disperse a portion of the heat which has been generated.

It is vital that the insulation utilized in a power transformer separates the different circuits, isolate the winding core and outer case from the circuits; provide mechanical support for the electrical coils and withstand the mechanical forces imposed by power system surges and short circuits. Generally, Kraft paper has been utilized for winding conductor insulation, high density pressboard for inter-winding and inter-phase insulation, and crepe paper for lead insulation. The critical properties that determine the functional life of dielectric oil/paper insulation are chemical purity, thermal stability, and mechanical and dielectric strengths. It is generally believed that failure occurs when a transformer component or structure is no longer able to withstand the stresses imposed on it during operation.

During the course of its life, the power transformer, as a whole, has suffered the impact of thermal, mechanical, chemical, electrical, and electromagnetic stresses during normal and transient loading conditions. The condition of the transformer deteriorates gradually, resulting in;

- reduction in dielectric strength (i.e. the ability to withstand lightning and switching impulses);
- reduction in mechanical strength (i.e. the ability to withstand any through faults);

- reduction in thermal integrity of the current carrying circuit (i.e. the ability to withstand overloads); and
- reduction in electromagnetic integrity (i.e. the ability to transfer electromagnetic energy at specified conditions including over-excitation and overloading).

A failure ultimately occurs when the withstand strength of the transformer with respect to any one of the above key properties is exceeded by operating stress.

TBHEDI conducts an annual power transformer inspection regime which includes[19];

- visual inspection for; oil leaks, bushing damage, oil levels, auxiliary component condition (i.e. fans radiator), and conservator tank rupture;
- oil screen and moisture content testing;
- dissolved gas analysis; and,
- furanic compound testing.

Dissolved Gas Analysis

Dissolved gas analysis (DGA) is an efficient tool for the purposes of monitoring the in-service behaviour of costly power transformers[20]. It can warn of imminent failures, enable early diagnostics, and provide opportunity for corrective maintenance.

The operating principle of DGA is based upon the deterioration of insulation which is caused by incipient faults (in the form of arcs or sparks) resulting from dielectric breakdown of weak/overstressed parts of the insulation or hot spots caused by

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[19] In the event of a tap change, TBHEDI will perform a ratio-meter test and micro-ohmeter confirmation test and also conducts megger testing of transformer windings every 3-5 years.

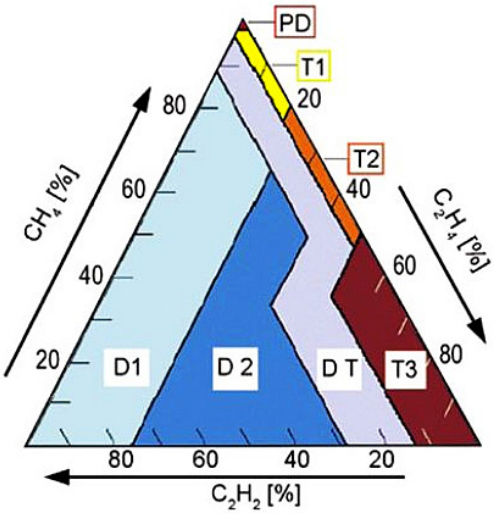
[20] "Dissolved Gas Analysis: It Can Save Your Transformer", M. Duval, November/December 1989 IEEE Electrical Insulation Magazine

abnormally high current densities in conductors. These stresses result in the chemical breakdown of some of the oil or cellulose molecules which constitute the dielectric insulation. The main degradation products of this reaction are gases which entirely or partially dissolve in the oil where they are easily detected at the ppm[21] level by DGA.

The main gases formed as a result of electrical and thermal faults in transformers and evaluated by DGA are; hydrogen, acetylene, ethylene, ethane, carbon monoxide, and carbon dioxide. The relative concentrations of these gases are indicative of the type of degradation being experienced within the transformer.

A general rule, based on thermodynamic considerations, is that the degree of chemical unsaturation (of the gases formed) is related to the energy density of the fault. Acetylene is thus mainly associated with arcing (where temperatures reach several thousand degrees), ethylene with hot spots between 150 C and 1000 C, etc. Figure 28 shows the Duval Triangle diagnostic method for oil-insulated high-voltage equipment. Using this device, analysts can plot the relative concentrations of dissolved gases to infer the approximate health of TBHEDI power transformers.

[21]PPM: Parts per million



PD = Partial Discharges

T1 = Overheating below 300°C

T2 = Overheating in range 300 ÷700°C

T3 = Overheating above 700°C

D1 = Low energy discharges

D2 = High energy arc

DT = Overheating and electric failures

Figure 28 - Duval's Triangle for DGA Diagnostics[22]

Furan Testing

When cellulose insulation (paper) decomposes due to overheating, chemicals are released and dissolve in the oil, these chemical compounds are known as furanic compounds, or furans. The oil of healthy transformers (or of a transformer recently flushed and refilled) contains no furanic compounds (<100ppb[23]). As the cellulose degrades the furan levels increase. Furan levels of 500 to 1000ppb are indicative of accelerated cellulose aging. Furan levels in excess of 1500ppb indicate a high risk of insulation failure[24]. It is standard practice within the industry to conduct follow up furan testing when DGA has detected the presence of cellulose breakdown.

The present condition of TBHEDI's 27 substation power transformers is shown in Table 9. The transformer risk ratings are based on; the age of the transformer relative to the

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[22] http://www.energo-complex.com/badania,transformatory-mocy,ocena-stanu-technicznego.php

[23] ppb: Parts per billion

[24] http://www.netaworld.org/files/neta-journals/NWwtr09_Hamrick.pdf

accepted typical useful life[25], and the condition rating per IEEE C57.104-2008, “IEEE Guide for the Interpretation of Gases Generated in Oil-Immersed Transformers”. The overall risk rating is a grade out of 5 where 5 is the highest level of risk. In general, transformer risk is used as a prioritization index for the planning of medium to long term capital replacement efforts. The overall risk index classification and follow-up activities are as found in Table 8;

[25] Typical useful life of power transformer is assumed to be 45 years per, “Asset Depreciation Study for the Ontario Energy Board”, conducted by Kinetrics, July 8, 2010.

Overall Risk Level	TBHEDI Risk Class	Follow-Up Activity
4.0 – 5.0	High	• Increase frequency of inspections and testing to 3 month increments • Ensure validity of capital replacement forecast
3.5 – 3.9	Med-High	• Increase frequency of inspections and testing to 6 month increments • Include asset replacement in mid to long term capital replacement
3.0 - 3.4	Med-Low	• Maintain inspection and testing frequency • Include asset replacement in long term capital requirements
0.0 – 2.9	Low	• Inspect and test annually

Table 8 - TBHEDI Power Transformer Risk Index Classification

Substation	Transformer ID	Secondary Voltage	Transformer Age*	DGA Condition Rating	Overall Risk
Windemere	21T1	4kV	57	3	4.4
McPherson	6T1	4kV	55	3	4.4
Hardisty	3T1	4kV	64	2	3.8
Brock	22T1	4kV	64	2	3.8
Hardisty	3T2	4kV	60	2	3.8
MacDonnell	16T1	4kV	59	2	3.8
Mary	7T1	4kV	58	2	3.8
Algoma	14T1	4kV	54	2	3.8
High	11T1	4kV	53	2	3.8
Alice	23T1	12kV	41	2	3.5
Brock	22T2	4kV	60	1	3.1
Donald	5T1	4kV	55	1	3.1
MacDonnell	16T2	4kV	54	1	3.1
Vickers	4T2	4kV	54	1	3.1
Windemere	21T2	4kV	54	1	3.1
Balsam	18T1	4kV	53	1	3.1
Donald	5T2	4kV	50	1	3.1
Mountdale	9T1	4kV	47	1	3.1
Mary	7T2	4kV	46	1	3.1
Mapleward	36T1W	12kV	45	1	3.1
Mapleward	36T1B	12kV	45	1	3.1
Mapleward	36T1R	12kV	45	1	3.1
Camelot	12T1	4kV	44	1	3.1
Camelot	12T2	4kV	44	1	3.1
Grenville	15T1	4kV	44	1	3.1
Balsam	18T2	12kV	41	1	2.9
Broadway	19T1	12kV	33	1	2.5

***Transformer ages shown in red exceed 45 year typical useful life**

Table 9 - TBHEDI Power Transformer Condition

Circuit Breakers

When a fault occurs on the distribution system, the associated fault current must be interrupted quickly and reliably. If a breaker fails to clear a faulted circuit the resulting damage can be catastrophic in terms of personnel injury and equipment damage. Even though circuit breakers are inherently reliable, circuit breaker failures can and do occur. TBHEDI employs air circuit breakers, vacuum circuit breakers, and oil circuit breakers, the characteristics of these breakers are as follows.

Air Circuit Breaker

Air circuit breakers are common within medium voltage electrical distribution systems and include mechanisms that are mainly exposed to the environment.

A typical air circuit breaker includes a main contact assembly which makes (closes the electrical path) or breaks (opens the electrical path) a circuit. The force necessary to open or close the main contact is provided by an arrangement of compression springs. The mechanism for controlling the compression springs is comprised of mechanical linkages between a latching shaft and an actuation device. The actuation device may be manually operated or electrically operated with trip (open) and close coils. In a typical medium voltage air circuit breaker, the movable contact is mounted on a contact arm that is pivoted to open or close the contacts by a spring powered operating mechanism which is triggered by the trip or closing coils by a control switch or closing relay (i.e. protective relay). Smaller opening springs are put in tension during closing and assist in opening when the trip coil is energized from the control switch or protective relays. The current interruption capability of air circuit breakers is dependant, in part, on their ability to extinguish the arc that is generated when the main contacts open or close.

Vacuum Circuit Breaker

Vacuum circuit breakers are similar to air circuit breakers with the difference being that the main contacts are housed in a vacuum chamber (the ‘bottle’). One of the contacts is fixed relative to the bottle and to an external conductor which is interconnected with the circuit that is to be protected by the circuit breaker.

Vacuum circuit breakers offer many advantages as compared to other types, including; relatively long life due to controlled contact erosion, maintenance free operation provided by enclosure of the contact within the hermetically sealed housing, excellent operational reliability due to the use of hard contact materials, little or no atmospheric contact contamination (contamination can detrimentally form oxides and corrosion layers on the contacts), and little or no noise during operation due to containment of arcing within the hermetically sealed housing[26].

Oil Circuit Breaker

Oil circuit breakers were the standard circuit breaker of the past but are becoming less common as they are replaced by air or vacuum circuit breakers. Oil circuit breakers have all contacts and operating mechanisms housed within a sealed, oil filled tank which provides both the insulation of the operating mechanism and arc quenching capabilities. A typical oil circuit breaker includes the same operational characteristics as an air circuit breaker.

TBHEDI Breaker Inspection

TBHEDI performs visual inspection monthly and a detailed inspection of all substation circuit breakers once every three years. During the annual inspection the device is operated, a detailed visual inspection is performed, and technicians apply industry standard testing.

The visual inspection includes monitoring for visible signs of malfunction or degradation of the following breaker assemblies and their associated components (where visible and applicable);

- Draw out assembly;
- Main contacts;

[26] A Primer for Testing Medium-Voltage Breakers in the Industrial Environment, Lynn Hamrick, Summer 2010 NETA World.

- Pallet switches;
- Closing mechanism;
- Trip mechanism; and,
- Closing relay.

Device operation confirms the function of the following components;

- Closing relay;
- Motor; and,
- Trip/close circuit.

Finally, contact resistance, insulation resistance, and dielectric withstand voltage tests are performed to complete the inspection.

The results of these tests are recorded by TBHEDI staff and filed accordingly. In the event that a technician determines, through inspection, that breaker maintenance is required, the Maintenance Supervisor the work which is executed according to priority.

TBHEDI Breaker Demographics

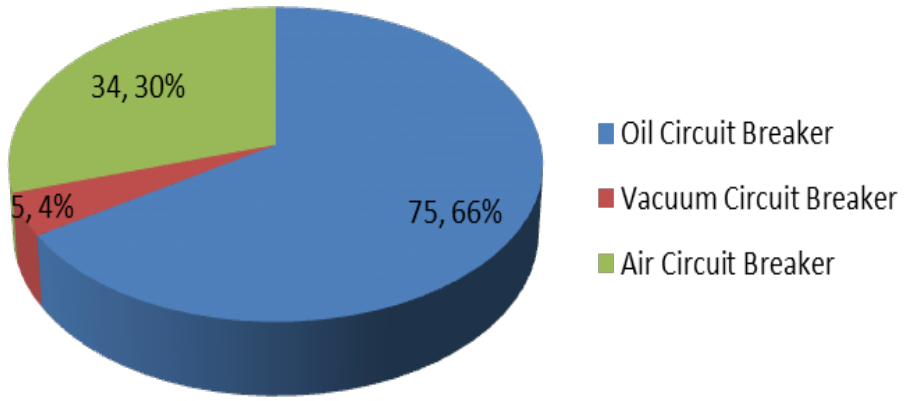

Figure 29 - TBHEDI Distribution of Breaker Types

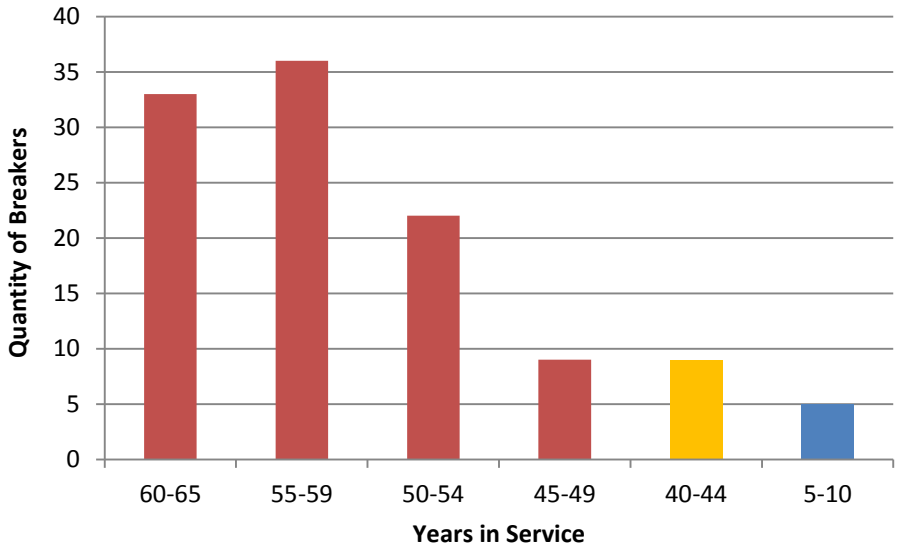

Figure 30 - Age Distribution of TBHEDI's 114 Substation Breakers (Columns in red indicate breakers at or beyond the typical useful life[27] of 45 years)

Reclosers

TBHEDI employs reclosers as head node protections at the 12kV substations[28]; Alice (Station 23), Mapleward (Station 36), and Broadway (Station 19).

Reclosers are self-contained, mechanical switching devices used to detect and automatically isolate fault conditions. The name, 'recloser', results from the device's ability to automatically reclose in a predetermined, timed reclosing sequence.

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[27] Typical useful life of station breaker is assumed to be 45 years per, "Asset Depreciation Study for the Ontario Energy Board", conducted by Kinetrics, July 8, 2010.

[28] Balsam St. substation (Station 18), while 12kV, employs conventional circuit breakers for feeder protections.

Reclosers consist of a tank or enclosure, insulating assemblies, moving contacts, an interrupting medium, and auxiliary devices. Auxiliary devices include trip and close coils, batteries, etc.

The TBHEDI recloser population is largely maintenance free. TBHEDI Substation technicians do however perform visual inspections on a monthly basis. Reclosers are removed from service and returned to the manufacturer once every three years for diagnostic testing and calibration.

Visual inspection targets include;

- Oil tank condition (where applicable);
- termination contacts; and,
- insulator bushings.

The TBHEDI substation recloser population is as follows;

Station	Recloser Model	Recloser Age	Quantity
19	NOVA-15	12 Years	3
23	VXE-15	17 Years	6
36	VXE-15	17 Years	3
36	Viper	1 Year	3

Table 10 - TBHEDI Substation Recloser Population

Auxiliary Station Equipment

As a part of the annual substation inspection, TBHEDI staff also monitor the following asset classes:

Battery Banks

TBHEDI employs battery banks in the majority of its substations for the provision of emergency power under emergency conditions. Battery bank testing is carried out annually in accordance with IEEE Std 1106-2005, “IEEE Recommended Practice for Installation, Maintenance, Testing, and Replacement of Vented Nickel-Cadmium Batteries for Stationary Applications”. Where possible, technicians maintain battery fluid

levels on a monthly basis. When testing determines that a battery has reached the end of its life, the unit is replaced at the discretion of the station maintenance supervisor.

SCADA Infrastructure

TBHEDI substations (and a number of remotely operable switches) are equipped with a remote terminal unit (RTU) which; monitors and reports power system inputs to System Control Operators, and allows System Control Operators a degree of remote operability of switching devices (breakers, reclosers, and switches). TBHEDI technicians inspect and test SCADA components annually. Battery units associated with SCADA infrastructure are maintained as described previously on an annual basis.

Protective Relays

A protective relay is, “an electric device that is designed to respond to input conditions in a prescribed manner and, after specified conditions are met, to cause contact operation or similar abrupt change in associated electric control circuits”[29].

TBHEDI employs both electromechanical and solid state protective relays across the 4kV and 12kV feeder head nodes. While the settings applied to solid state relays are quite stable, the response of an electromechanical relay depends upon moving parts which demand frequent calibration in order to ensure consistent fault response.

TBHEDI inspects and calibrates all protective relays every three years.

Review of Substation Inspection Procedures and Findings

TBHEDI substation assets represent a substantial investment and, potentially, a substantial liability. The monthly inspection regime meets the regulatory requirement for ‘outdoor open’ distribution stations and exceeds the requirement for ‘indoor enclosed’ installations.

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[29] IEEE definition of ‘protective relay’

67% of the TBHEDI substation power transformers are beyond their typical useful life, all of which are 4kV assets. This condition is addressed as a part of the TBHEDI voltage conversion program.

88% of the TBHEDI substation circuit breakers are at or beyond their typical useful life, all of which are 4kV assets. This condition is addressed as a part of the TBHEDI voltage conversion program.

The substation component of the TBHEDI Asset Condition Assessment is detailed in its approach and consistent with industry best practices. TBHEDI intends to continue to conduct this inspection as described herein. TBHEDI further intends to enhance the data management techniques as they pertain to this inspection by introducing electronic data collection, automated work order generation, and centralization of the inspection database. Data management enhancements are targeted for development in 2013.

TBHEDI RELIABILITY STATISTICS

In compliance with the mandate of the Ontario Energy Board, TBHEDI tracks the utility's reliability indices (SAIDI[30], SAIFI[31], CAIDI[32], and MAIFI[33]) and reports them on a quarterly basis. For the purposes of these quarterly reports, an outage is considered 'momentary' where it is less than one minute in duration and a 'sustained interruption' where greater than one minute. Part power situations, customer interruption requests, non-payment disconnections, and safety related disconnections do not contribute to the reported indices.

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[30] SAIDI: System Average Interruption Duration Index

[31] SAIFI: System Average Interruption Frequency Index

[32] CAIDI: Customer Average Interruption Duration Index

[33] MAIFI: Momentary Average Interruption Frequency Index – Reporting of this index began in 2009.

In addition to the overall reliability indices TBHEDI categorizes each outage event by one of the definitions contained in Table 11**.** Reporting in this manner allows for analysis of past and current levels of maintenance, sufficiency and effectiveness of the vegetation management program, problematic components (further analysis of which may lead to the discovery of systematic issues, i.e. a particular brand of component may be expected to fail at a disproportionate rate), and opportunities for system improvements which may substantially impact the customer's experience.

Outage Category	Definition
Scheduled Outage	Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventative maintenance.
Loss of Supply	Customer interruptions due to problems in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.
Tree Contacts	Customer interruptions caused by faults resulting from tree contact with energized circuits.
Lightning	Customer interruptions due to lightning striking the distribution system, resulting in insulation breakdown and /or flashovers.
Defective Equipment	Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.
Adverse Weather	Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Tree Contacts and Lightning)
Human Element	Customer interruptions due to the interface of distributor staff with the distribution system.
Foreign Interference	Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects
Unknown/Other	Customer interruptions where no cause was able to have been established.

Table 11 - TBHEDI Outage Event Classification

As prescribed by the corporation's objectives, TBHEDI endeavours to reduce the impact of outage causes where mitigation of these causes falls under the reasonable control of

the utility. Examples of manageable outage causes and their associated mitigation activities are;

Scheduled Outages:

- Deployment of additional fused cutouts or in-line switches prior to extensive area construction or maintenance activities reduces the extent of outages required for work protection.

Tree Contacts:

- An extensive vegetation abatement program has proven to significantly reduce these occurrences.
- An initiative targeted at public awareness of the impact that privately managed vegetation may have on distribution system performance should overgrowth be permitted.

Defective Equipment:

- It is a primary objective of the Asset Management Plan to monitor asset health and replace/maintain defective components before they detrimentally affect system reliability.

Foreign Interference:

- Application of animal protection where applicable (e.g. bushing extension, heat shrink in overhead construction, blocking access to underground pads, etc.);
- Reducing the locations or installations prone to animal contact (e.g. 3 phase dip poles and use of alumaform brackets);
- Employment of high visibility markers and physical barriers where an installation is exposed to motor vehicle traffic, and;
- Ongoing campaigns which are designed to heighten the public awareness of the importance of obtaining underground infrastructure locates.

Where mitigation of outage causes is not reasonably within the control of TBHEDI, or where mitigation efforts fall short of the complete elimination of the cause, TBHEDI endeavours to design and construct a robust distribution system with contingencies where feasible and strategic deployment of remotely operated switching components. This strategy enables operators to respond to inevitable and/or unavoidable outage events with greater speed and improved truncation of outage events.

The following charts provide a summary of the statistics compiled by TBHEDI System Control personnel. These statistics are routinely analysed to extract geospatial patterns, asset or sub-network specific deficiencies, or operational anomalies.

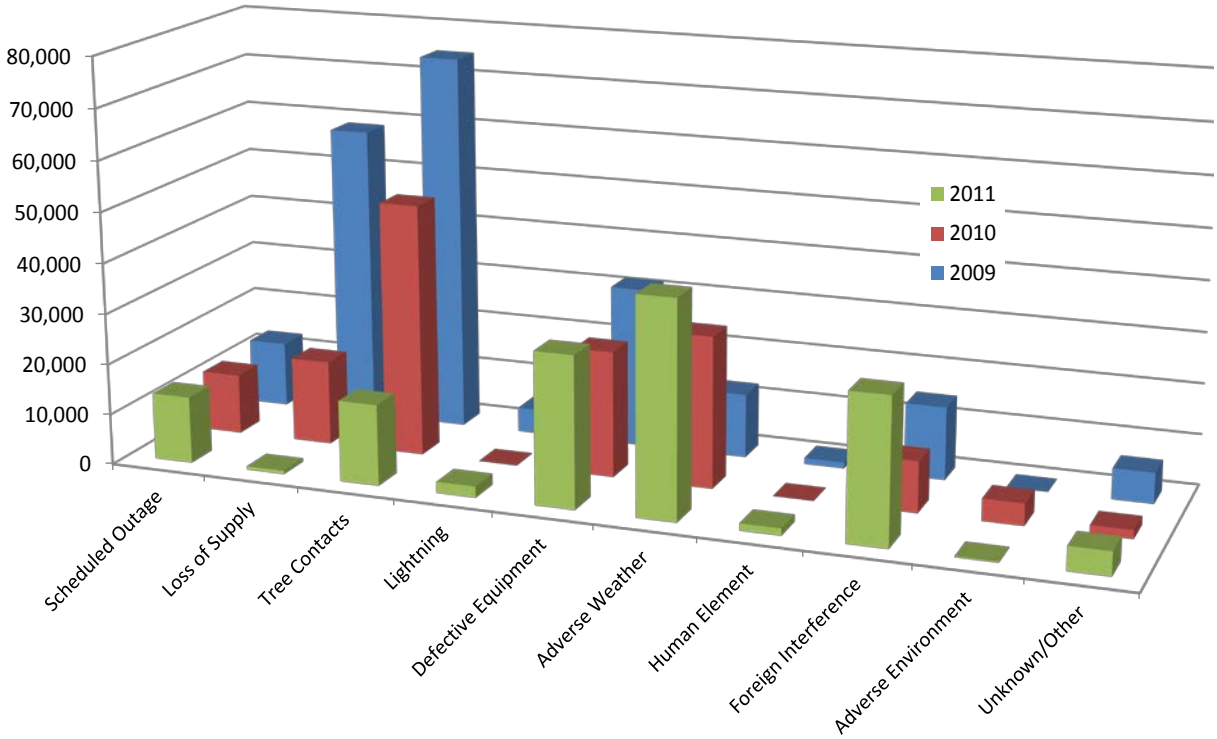

Figure 31 - Outage Hours by Cause Classification

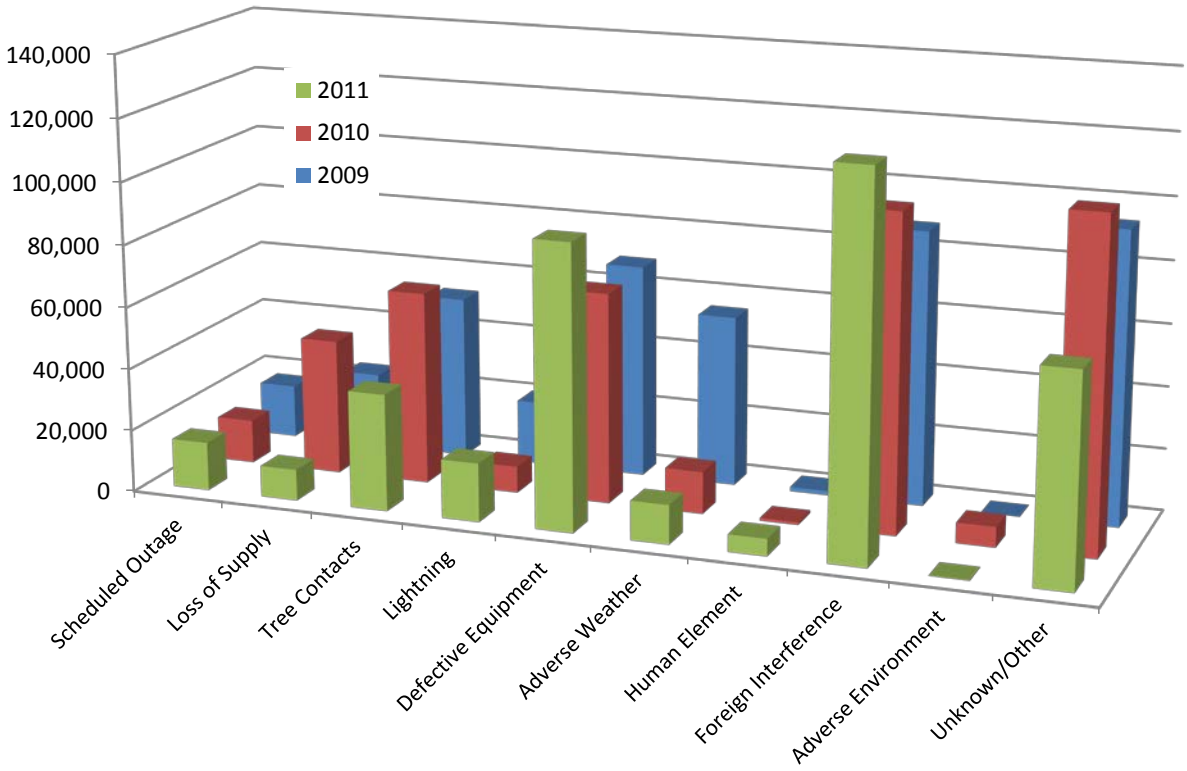

Figure 32 - Customer Interruptions by Cause Classifications (Includes momentary interruptions)

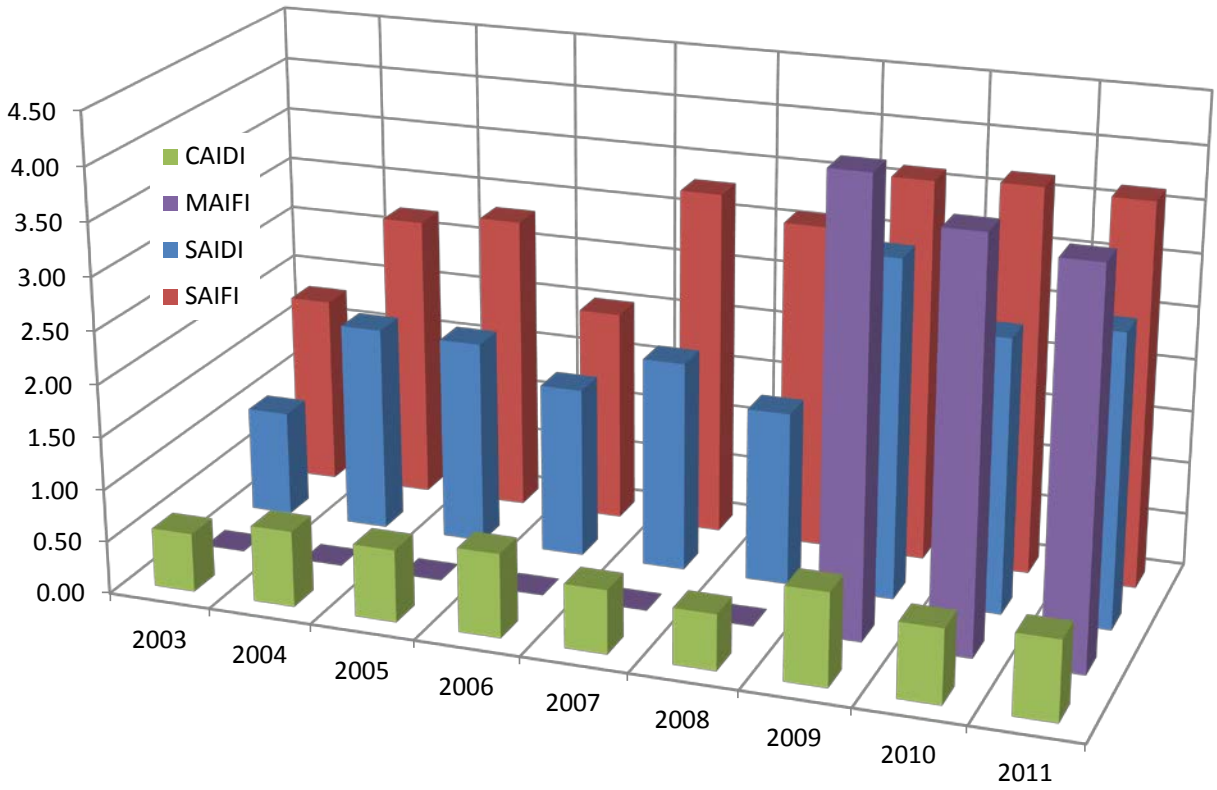

Figure 33 - Historic Reliability Indices[34]

[34] The following should be noted with respect to historic system reliability indices:

- The contribution of 'Loss of Supply' is included in indices prior to 2009 and excluded from 2009-2011;
- MAIFI was not reported until 2009, the 2009 index includes 'Losss of Supply', the 2010 & 2011 indices do not,

SECTION 2: TBHEDI FORESTRY MANAGEMENT PROGRAM

INTRODUCTION

TBHEDI's overhead conductors occupy a linear thoroughfare of approximately 869 km. It is the responsibility of TBHEDI Forestry Coordinator to ensure that vegetation does not encroach upon these overhead distribution conductors beyond acceptable limits. Overgrowth of vegetation may threaten the safety of the public, TBHEDI employee's and can contribute to distribution system faults which may result in unscheduled service interruptions.

Until recently, TBHEDI's forestry management was conducted on a small scale and on an "as needed" basis. This was in keeping with an effort to maintain customer's electricity rates as low as possible. The historical vegetation management spending is found in Figure 34.

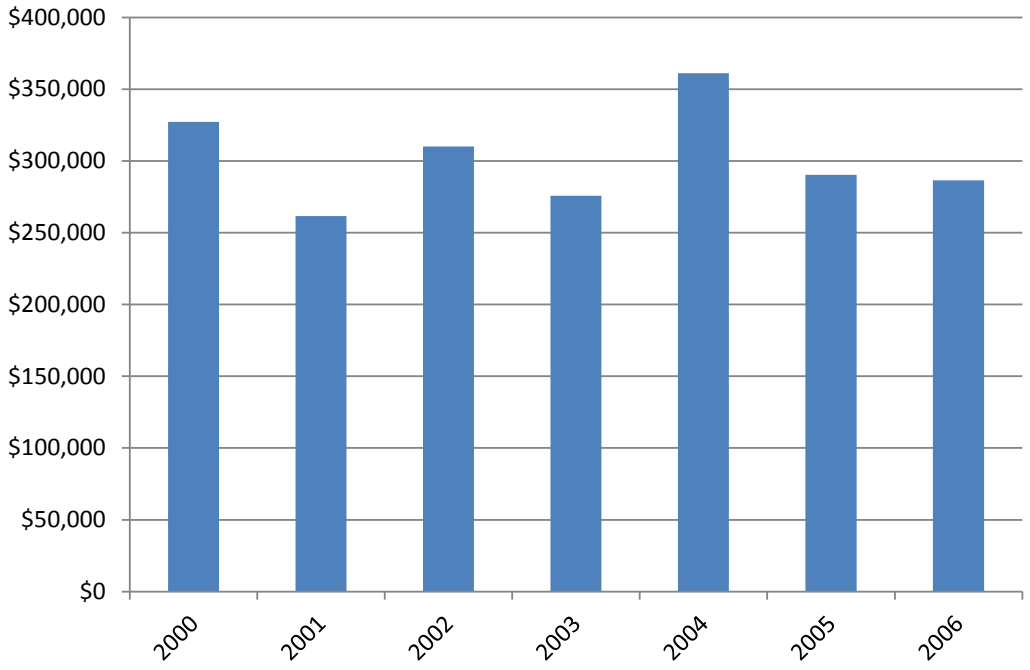

Figure 34 - Historical TBHEDI Vegetation Management Spending

In 2007 and 2008, TBHEDI conducted a system wide risk assessment with the intention of determining the overall level of vegetation overgrowth. The outcome of this risk assessment is as follows;

Percent of all overhead lines exposed to potential interference by vegetation:	80%
Percent of all overhead lines requiring immediate vegetation management intervention:	40%

The approximate distribution of overhead lines exposed to vegetation infiltration and the associated cost/metre for management of that vegetation is as follows. Note that these costs assume that the vegetation has been sustainably maintained and that only limited trimming is required.

Overhead Line Configuration	Km Exposed to Vegetation	%Impeded Vehicle Access	Cost/metre where Vehicle Access is Impeded	% Non-Impeded Vehicle Access	Cost/metre where Vehicle Access is Non-Impeded
One Circuit Per Pole and Less	615.3	45%	$5.25	55%	$2.75
Two Circuits Per Pole and Greater	79.9	30%	$9.25	70%	$5.25
Total Estimated Vegetation Management Cost:					$3.624M

Table 12 - TBHEDI Vegetation Management Sustainment Budget

Given the costs provided in Table 12, TBHEDI estimates that the annual forestry sustainment budget (assuming the industry standard 7 year cutting cycle) should be in the order of $517,800. Comparing this value to those in Figure 34 it is readily apparent that, historically, vegetation management was not taking place at a sustainable rate.

TBHEDI has acknowledged that the backlog of vegetation overgrowth cannot be effectively remediated by simply adopting the sustainment level of trimming immediately. As such, TBHEDI has adopted an escalated forestry management plan in order to return vegetation growth in overhead line thoroughfares to sustainable levels.

OBJECTIVE

The near term objective of the TBHEDI Forestry Management Program is to systematically address all areas of significant vegetation overgrowth in an effort to return vegetation management to sustainable levels.

STRATEGY

Based on the results of the 2007/2008 vegetation risk assessment, TBHEDI has established that the sustainable rate of vegetation abatement can be achieved in a 10 year period. During this period, the cost/metre is greater than the sustainment rate given the substantial amount of vegetation trimming and clearing which must be undertaken in order to curb growth to a degree which will allow for the standard 7 year management period. The escalated vegetation management figures which accommodate present levels of infiltration are shown in Table 13. TBHEDI reached the escalated management rate in 2009.

Overhead Line Configuration	Km Exposed to Vegetation	%Impeded Vehicle Access	Cost/metre where Vehicle Access is Impeded	% Non-Impeded Vehicle Access	Cost/metre where Vehicle Access is Non-Impeded
One Circuit Per Pole and Less	615.3	45%	$18.41	55%	$4.08
Two Circuits Per Pole and Greater	79.9	30%	$30.86	70%	$8.03
Total Estimated Vegetation Management Cost:					$7.667M
Annual Vegetation Management Cost (Total/10 Years)					$767,000

Table 13 - TBHEDI Escalated Vegetation Management Budget

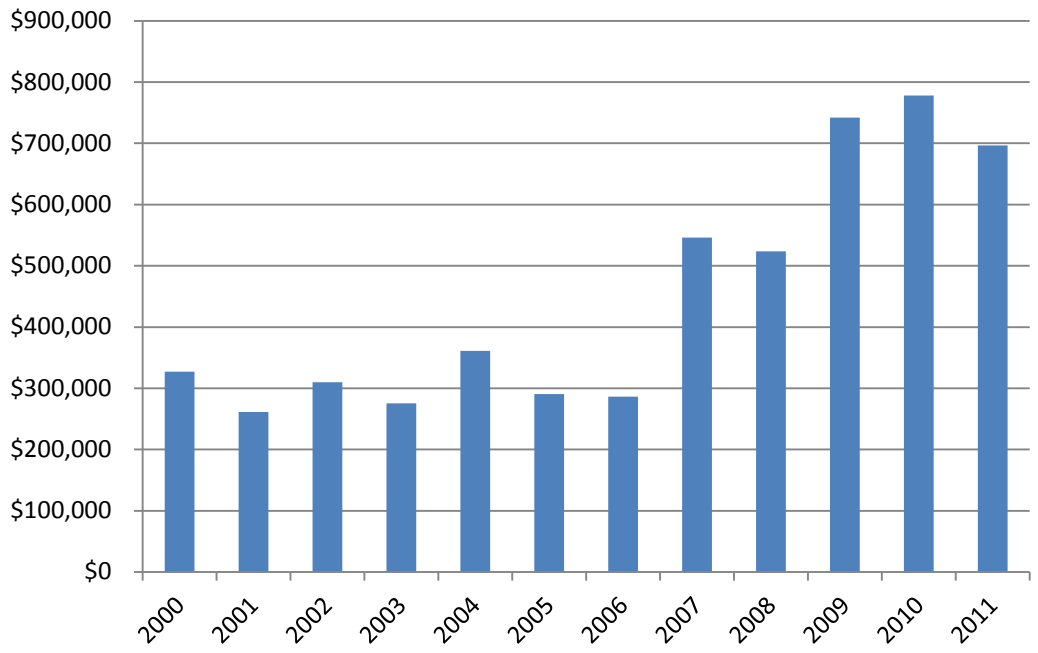

Figure 35 - TBHEDI Vegetation Management Budget Escalation

CURRENT PROJECTS

In recent years, TBHEDI Forestry Operations has been assigned to the clearing of areas where TBHEDI line construction crews are scheduled to arrive and conduct large scale capital reconstruction projects. These areas are consistent with the objectives of the Forestry Management Program given that the targeted laneways are often overgrown and require significant cut back. Upon completion of the “capital project” trimming requirements, forestry personnel will transition their efforts to;

- The 23F1 circuit (a rural circuit significantly impacted by vegetation contacts);
- The Red River/John St/Junot/Algonquin urban, residential area which is not scheduled for capital reconstruction for some time yet whose vegetation overgrowth has begun to produce customer complaints and has potential to contribute to significant outages; and,
- The Arthur/Walsh/Syndicate/Franklin area (for the same reasons as above).

In addition to these projects, TBHEDI Forestry Operations will also be required to provide support for storm response and spot maintenance activities.

The 2012 TBHEDI Forestry Management budget has been set at $720,000.

FORECASTED FORESTRY OPERATIONS (2013 & ONWARD)

The systematic approach of managing interfering vegetation by conducting large scale, area clearing rather than dealing with problems as they arise has returned significant and notable results. “After hours” overhead line related callouts have been reduced, safety has been enhanced for the public and the TBHEDI employee, and the reliability of feeders, which were formerly subject to high vegetation penetration, has been improved.

Area delineated operations will continue and, while customer requests for clearing are dealt with in a timely manner, the focus will remain on the clearing of large areas in order to provide a future baseline for the industry standard, 7 year, trimming cycle.

In spite of the efforts taken by TBHEDI thus far, there remains a considerable amount of work for TBHEDI Forestry Coordinator in order to eliminate the vegetation backlog. Trees that were trimmed early in the program are beginning to require attention again and TBHEDI notes that extreme weather events have become more frequent, increasing the urgency of the continued escalated program.

Future operations will continue to focus on the semi-rural areas as the response time for power restoration is hindered in these areas due to substantial overgrowth.

Funding levels are anticipated to remain constant for approximately 4-5 years in order to achieve clearing of all high priority vegetation concerns.

SECTION 3: TBHEDI PCB MANAGEMENT PROGRAM

INTRODUCTION

Polychlorinated biphenyls, or PCBs, are mixtures of up to 209 individual chlorinated compounds. PCBs do not occur naturally; they are colorless to light yellow, and have no known smell or taste.

PCBs have been used as coolants and lubricants in transformers, capacitors and other electrical equipment because they don't burn easily and are good insulators.

PCB production was stopped in 1977 when evidence showed that they built up in the environment and exposure to them caused acne-like skin conditions in adults and neurobehavioral and immunological changes in children.

It is for these reasons that the Canadian Environmental Protection Act includes regulations and has proposals in place that will ensure PCB elimination.

General PCB Information

- One part per million (ppm) is the equivalent to one mg/kg.
- A high PCB contamination level is >10,000 ppm.
- A medium PCB contamination level is 500 – 10,000 ppm.
- A low PCB contamination level is 50 – 500 ppm.
- As of 2011 contaminated oil between 2 – 50 ppm can no longer be picked up by a local waste management company and subsequently will be picked up and shipped via a contracted PCB destruction company
- Sensitive areas are areas within 100 meters of a school, food processing facility or water treatment plant, hospital and child care facilities.
- TBHEDI is a licensed generator of PCB waste ONO171700.
- TBHEDI Site Identification number for 37 Front Street is 601 86 A 009.

PCB Strategic Plan

- To comply with legislative requirements TBHEDI has established a detailed action plan to systematically remove and destroy all identified PCB transformers and other pieces of PCB equipment.
- TBHEDI's Power Systems Division will over the projected completion horizon of the PCB Management Plan be requesting approximately 1.85 million dollars to fulfill all present legislated PCB use and destruction requirements.

2008 PCB Plan

- TBHEDI continued their practice of decommissioning and scrapping all transformers that are brought back to the transformer shop each year through voltage conversions, new construction or upgrades which exceed 2 ppm PCB.
- TBHEDI disposed of all accumulated >50 PPM PCB oil and >50 PPM PCB waste by year end.

2009 PCB Plan

- TBHEDI replaced 100% (33) of the transformers and other pieces of equipment that were identified as >500 PPM PCB.
- TBHEDI replaced 100% (5) of the transformers that were identified as being near sensitive areas.
- TBHEDI replaced 12 other >50 PPM PCB transformer
- TBHEDI disposed of all >50 PPM PCB oil and >50 PPM PCB waste accumulated in 2009 by year end.

2010 PCB Plan

- TBHEDI replaced 10% (23) of the 233 transformers that were identified as >50 PPM PCB, plus 3 additional >50 PPM PCB transformers.
- TBHEDI disposed of all >50 PPM PCB oil and >50 PPM PCB waste accumulated in 2010 by year end.

2011 PCB Plan

- TBHEDI replaced 10% (23) of the 233 transformers that were identified as >50 PPM PCB, plus 2 additional >50 PPM PCB transformers.
- TBHEDI disposed of all >2 PPM PCB oil and >50 PPM PCB waste accumulated in 2011 by year end.

2012 PCB Plan

- TBHEDI is committed to replacing 10% (23) of the 233 transformers that were identified as >50 PPM PCB.
- For 2012 TBHEDI will dispose of all accumulated >2 PPM PCB oil and >50 PPM PCB waste by year end.

2013 PCB Plan

- TBHEDI is committed to replacing 10% (23) of the 233 transformers that were identified as >50 PPM PCB.
- For 2013 TBHEDI will dispose of all accumulated >2 PPM PCB oil and >50 PPM PCB waste by year end.

2014 PCB Plan

- TBHEDI is committed to replacing 10% (23) of the 233 transformers that were identified as >50 PPM PCB.

- For 2014 TBHEDI will dispose of all accumulated >2 PPM PCB oil and >50 PPM PCB waste by year end.

2015 PCB Plan

- TBHEDI is committed to replacing 10% (23) of the 233 transformers that were identified as >50 PPM PCB.
- For 2015 TBHEDI will dispose of all accumulated >2 PPM PCB oil and >50 PPM PCB waste by year end.

2016 PCB Plan

- TBHEDI is committed to replacing 10% (23) of the 233 transformers that were identified as >50 PPM PCB.
- For 2016 TBHEDI will dispose of all accumulated >2 PPM PCB oil and >50 PPM PCB waste by year end.

2017 PCB Plan

- TBHEDI is committed to replacing 10% (23) of the 233 transformers that were identified as >50 PPM PCB.
- For 2017 TBHEDI will dispose of all accumulated >2 PPM PCB oil and >50 PPM PCB waste by year end.

2018 PCB Plan

- TBHEDI is committed to replacing the remaining 17 of the 233 transformers that were identified as >50 PPM PCB.
- For 2018 TBHEDI will dispose of all accumulated >2 PPM PCB oil and >50 PPM PCB waste by year end.

LEGAL REQUIREMENTS

The proposed legislation is broken into three parts. Part one sets out the deadlines for phasing out the use of PCBs and PCB products.

Part two sets out the storage requirements for PCBs and products containing PCBs that are no longer in use.

Part three sets out the end of use labeling and reporting requirements for PCBs and products containing PCBs that may continue to be used or that are stored for specific periods.

The key element of the proposed Regulations is the prescribed end of use deadlines for liquids containing PCBs and PCB contaminated equipment that is still in use or temporarily out of service.

Part 1 - PCB End of Use Deadline

Removal of this equipment by the dates indicated is required to comply with legislation.

- For equipment containing PCBs in a concentration of 500 ppm or more:
  - December 31, 2009.
- For equipment containing PCBs in a concentration of at least 50 ppm but less than 500 ppm:
  - December 31, 2009 when located in sensitive locations.
  - December 31, 2014 for pad mount equipment
  - December 31, 2025 at all other locations.

Part 2 - PCB End of Storage Deadline

The legislated end of storage dates and storage time periods for PCBs and products containing PCBs with a concentration of 50 ppm or more are as follows:

A storage period of one year is allowed for PCBs and PCB contaminated products at the following locations:

- At the owner's PCB storage site.
- At the PCB storage site of an authorized facility for decontamination.
- At the PCB storage location of an authorized transfer site.
- At the PCB storage site of an authorized destruction facility.
- Within 100 m of a sensitive location.

Part 3 - PCB Reporting and Identification Requirements

A written report for PCBs in use and in storage is submitted to the Ministry of Environment and Energy (MOEE) annually and is to include the following:

- An inventory of PCB oil, PCB contaminated equipment in use and our plan to progress towards the end of use deadlines including time lines and destruction dates.
- An annual written report summarizing the quantities of PCB oil or PCB contaminated products that were manufactured, imported, exported, sold, offered for sale, used or processed at a laboratory or research facility.
- Notification and a written report to an enforcement officer or a person identified in the proposed Regulations for any PCB release into the environment or the likelihood of a release. This report shall indicate the estimated quantity of PCBs released, the environment affected by the release, and other information as required in the Regulations.
- Accurate and detailed inventory information on any PCBs in storage.

The Regulations also prescribe the analytical methods and standards to be used to determine the concentration of PCBs for the purpose of determining compliance with the proposed Regulations.

Identification is Required:

- On all PCB equipment and containers in out of service or in storage until the day they are eliminated.
- On equipment, containers or products containing >50 PPM PCBs, the identification shall indicate the owner's name and date the products were put in storage.
- On electrical transformers decontaminated to a PCB concentration of <50 PPM, the identification shall indicate the owner's name and that the transformer is decontaminated.
- At PCB storage sites a notice indicating a PCB contamination level of >50 PPM in any of the equipment, containers or products stored at that site and the storage site owner's name.

There are some exceptions or alternatives to the labelling requirements based on practical considerations for in-use equipment already labelled, and for cables and pipelines.

TESTING TO DATE

PCB Testing History

- TBHEDI has approximately 7,300 distribution transformers, power transformers, primary metering units, circuit breakers and oil circuit reclosers presently in service.
- Approximately 500 units were field tested in 1987.
- 2,000 units were field tested in 2004.
- 2,338 units were field tested in 2007.
- All substation transformer oil has been tested and is <50 ppm PCBs.

Results from the 2007, 2004 and Earlier PCB Testing Campaigns

Number of transformers tested to date	PCB content less than 50 PPM	PCB content between 50 and 500 PPM	PCB content between 500 and 10,000 PPM	PCB content > 10,000 PPM
4838	4546	254	35	3
Number of transformers decommissioned to date	0	95	35	3
Total Remaining	4546	159	0	0

Table 14 - TBHEDI PCB Testing History (as of 2012)

BUDGETING

Budgeting considerations for TBHEDI:

- Advertising larger scale interruptions should they be required.
- Lines personnel will work with the Utility Work Protection Code (UWPC) as it relates to isolation and de-energization to ensure personnel safety and to the most efficient use of interruptions where transformers are to be replaced.
- Ensure all TBHEDI personnel (lines, stores, engineering, stations etc.) working hours and trucking charges for this project are entered on timesheets to track the true cost of this project.

Power Systems received funding in the 2008 budget to dispose of all existing PCB oil and PCB waste that was in storage at the end of 2008.

Power Systems received funding in the 2009 budget to replace the thirty three >500 PPM PCB transformers which are identified as >500 PPM PCB, the five >50 PPM PCB transformers that have been identified in proximity to sensitive areas, 12 other >50 PPM PCB transformers and to and to dispose of PCB oils and PCB waste that was in storage at the end of 2009.

For each future year of this program, TBHEDI Power Systems will request funding to replace and dispose of all targeted PCB equipment and or waste.

IDENTIFYING PRIORITIES

Identify Transformers to be removed

- To assist in timely equipment procurement Operations will provide a detailed list to engineering for all the >50 ppm PCB transformers that will be replaced by August of the preceding year; this list will detail each of the targeted transformer's voltage, KVA, sub group, serial number, TBHEDI number, address, PCB content etc.

MANAGING THE PROGRAM

PCB Oil and Solid Waste removal and Destruction

- TBHEDI's engineering group will oversee the specification / requisition entry process for all transformers required to fulfill this plan.
- TBHEDI's lines group will oversee the replacement of all targeted transformers.
- TBHEDI's Operations Department will acquire the services of a PCB Transportation and Destruction Contractor for the duration of the program.
- The station's group will assist in the safe loading of all PCB contaminated material, in preparation for transportation by the PCB Transportation and Destruction Contractor.
- The stations group will maintain accurate record keeping of material types and PCB concentrations removed from TBHEDI property for inclusion onto the transportation manifests.
- The stations group will maintain accurate records and update HTE.
- The stations group will maintain accurate record keeping of all PCB material movement for year-end reporting as per regulations of Canadian Environmental Protection Act.

- The stations group will maintain and archive all certificates of destruction as they are awarded.
- The stations group will maintain security of TBHEDI PCB storage facilities.
- Operations will review emergency plans regarding fires and spill response.

COST OF COMPLIANCE 2009

TBHEDI replaced 50 transformers identified as >50 ppm PCB in 2009

	Number of Transformers Replaced (pole top and pad mount)	Actual 2009 Capital Transformer Cost	Actual 2009 OM&A Cost to Replace the Transformers	Actual 2009 Combined OM&A and Capital Costs
Transformers >500 PPM PCB	33			
Transformers >50 PPM PCB contamination near sensitive areas.	5			
Transformers >50 PPM PCB	12			
Total	50	$101,412.28	$162,206.12	$263,618.40

Table 15 - Actual Cost of OM&A and Capital PCB Transformer Replacements in 2009 (i)

	Actual 2009 >50 PCB Oil Destruction Costs	Actual 2009 Solid PCB Waste Destruction Costs	Actual 2009 PCB Oil and Solid Waste Transportation Costs	Actual 2009 Combined PCB Transportation and Destruction Costs
Contamination > 50 PPM	$17,913.02	$9,684.59	$8,770.00	$36,367.61

Table 16 - Actual Cost of PCB Waste Transportation and Destruction in 2009 (ii)

Actual cost of replacing 50 PCB transformers (i)	$263,618.40
Actual cost of transporting and destroying PCB waste(ii)	$36,367.61
Grand Total to replace 50 transformers, transport and destroy PCB material for the year 2009	$299,986.01

Table 17 - Actual Cost of 2009 PCB Activities

COST OF COMPLIANCE 2010

10% (23) of the 233 transformers identified as >50 PPM PCB replaced in 2010.

	Number of Transformers Replaced (pole top and pad mount)	Actual 2010 Capital Transformer Cost	Actual 2010 OM&A Cost to Replace the Transformers	Actual 2010 Combined OM&A and Capital Costs
Transformers >50 PPM PCB	26	$41,908.65	$121,296.48	$163,205,13

Table 18 - Actual Cost of OM&A and Capital PCB Transformer Replacements in 2010 (i)

	Actual 2010 >50 PCB Oil Destruction Costs	Actual 2010 Solid PCB Waste Destruction Costs	Actual 2010 PCB Oil and Solid Waste Transportation Costs	Actual 2010 Combined PCB Transportation and Destruction Costs
Contamination > 50 PPM PCB	$6,378.75	$1,248.45	$3,500.00	$11,127.20

Table 19 - Actual Cost of PCB Waste Transportation and Destruction in 2010 (ii)

Actual cost of replacing 26 PCB transformers (i)	$163,205,13
Actual cost of transporting and destroying PCB waste(ii)	$11,127.20
Grand Total to replace 26 transformers, transport and destroy PCB material for the year 2010	$174,332.33

Table 20 - Actual Cost of 2010 PCB Activities

COST OF COMPLIANCE 2011

10% (23) of the 233 transformers identified as >50 PPM PCB + 2 additional >50 PPM PCB transformers were replaced in 2011

PCB contaminated oil ppm thresholds were lowered from >50 ppm to any oil >2 ppm PCB oil

	Number of Transformers Replaced (pole top and pad mount)	Actual 2011 Capital Transformer Cost	Actual 2011 OM&A Cost to Replace the Transformers	Actual 2011 Combined OM&A and Capital Costs
Transformers >50 PPM PCB	25	$59,605.70	$97,882.08	$157,487.78

Table 21 - Actual Cost of OM&A and Capital PCB Transformer Replacements in 2011 (i)

	Actual 2011 >2 PCB Oil Destruction Costs	Actual 2011 Solid PCB Waste Destruction Costs	Actual 2011 PCB Oil and Solid Waste Transportation Costs	Actual 2011 Combined PCB Transportation and Destruction Costs
Contamination > 2 PPM for oil and >50 PPM for other	$25,107.75	$1,568.90	$6,241.04	$32,917.69

Table 22 - Actual Cost of PCB Waste Transportation and Destruction in 2011 (ii)

Actual cost of replacing 25 PCB transformers (i)	$157,487.78
Actual cost of transporting and destroying PCB waste(ii)	$32,917.69
Grand Total to replace 25 transformers, transport and destroy PCB material for the year 2011	$190,405.47

Table 23 – Actual Cost of 2011 PCB Activities

ESTIMATED COST OF COMPLIANCE 2012

10% (23) of the 233 transformers identified as >50 PPM PCB will be replaced in 2012.

	Estimated Number of Transformers Replaced (pole top and pad mount)	Estimated 2012 Capital Transformer Cost	Estimated 2012 OM&A Cost to Replace the Transformers	Estimated 2012 Combined OM&A and Capital Costs
Transformers >50 PPM PCB	23	--	--	$138,000

Table 24 - Estimated Cost of OM&A and Capital PCB Transformer Replacements in 2012 (i)

	Estimated 2012 >2 PCB Oil Destruction Costs	Estimated 2012 Solid PCB Waste Destruction Costs	Estimated 2012 PCB Oil and Solid Waste Transportation Costs	Estimated 2012 Combined PCB Transportation and Destruction Costs
Contamination > 2 PPM for oil and >50 PPM for other	$30,000	$2,000	$7,000	$39,000

Table 25 - Estimated Cost of PCB Waste Transportation and Destruction in 2012 (ii)

Estimated cost of replacing 25 PCB transformers (i)	$138,000
Estimated cost of transporting and destroying PCB waste(ii)	$39,000
Estimated Total to replace 25 transformers, transport and destroy PCB material for the year 2011	$177,000

Table 26 - Estimated Cost of 2012 PCB Activities

ESTIMATED COST OF COMPLIANCE 2013

10% (23) of the 233 transformers identified as >50 PPM PCB will be replaced in 2013.

	Estimated Number of Transformers Replaced (pole top and pad mount)	Estimated 2013 Capital Transformer Cost	Estimated 2013 OM&A Cost to Replace the Transformers	Estimated 2013 Combined OM&A and Capital Costs
Transformers >50 PPM PCB	23	--	--	$138,000

Table 27 - Estimated Cost of OM&A and Capital PCB Transformer Replacements in 2013 (i)

	Estimated 2013 >2 PCB Oil Destruction Costs	Estimated 2013 Solid PCB Waste Destruction Costs	Estimated 2013 PCB Oil and Solid Waste Transportation Costs	Estimated 2013 Combined PCB Transportation and Destruction Costs
Contamination > 2 PPM for oil and >50 PPM for other	$30,000	$2,000	$7,000	$39,000

Table 28 - Estimated Cost of PCB Waste Transportation and Destruction in 2013 (ii)

Estimated cost of replacing 23 PCB transformers (i)	$138,000
Estimated cost of transporting and destroying PCB waste(ii)	$39,000
Estimated total to replace 23 transformers, transport and destroy PCB material for the year 2013	$177,000

Table 29 - Estimated Cost of 2013 PCB Activities

ESTIMATED COST OF COMPLIANCE 2014

10% (23) of the 233 transformers identified as >50 PPM PCB will be replaced in 2014.

	Estimated Number of Transformers Replaced (pole top and pad mount)	Estimated 2014 Capital Transformer Cost	Estimated 2014 OM&A Cost to Replace the Transformers	Estimated 2014 Combined OM&A and Capital Costs
Transformers >50 PPM PCB	23	--	--	$138,000

Table 30 - Estimated Cost of OM&A and Capital PCB Transformer Replacements in 2014 (i)

	Estimated 2014 >2 PCB Oil Destruction Costs	Estimated 2014 Solid PCB Waste Destruction Costs	Estimated 2014 PCB Oil and Solid Waste Transportation Costs	Estimated 2014 Combined PCB Transportation and Destruction Costs
Contamination > 2 PPM for oil and >50 PPM for other	$30,000	$2,000	$7,000	$39,000

Table 31 - Estimated Cost of PCB Oil Destruction 2014 (i)

Estimated cost of replacing 23 PCB transformers (i)	$138,000
Estimated cost of transporting and destroying PCB waste(ii)	$39,000
Estimated total to replace 23 transformers, transport and destroy PCB material for the year 2014	$177,000

Table 32 - Estimated Cost of 2014 PCB Activities

ESTIMATED COST OF COMPLIANCE 2015

10% (23) of the 233 transformers identified as >50 PPM PCB will be replaced in 2015.

	Estimated Number of Transformers Replaced (pole top and pad mount)	Estimated 2015 Capital Transformer Cost	Estimated 2015 OM&A Cost to Replace the Transformers	Estimated 2015 Combined OM&A and Capital Costs
Transformers >50 PPM PCB	23	--	--	$138,000

Table 33 - Estimated Cost of OM&A and Capital PCB Transformer Replacements in 2015 (i)

	Estimated 2015 >2 PCB Oil Destruction Costs	Estimated 2015 Solid PCB Waste Destruction Costs	Estimated 2015 PCB Oil and Solid Waste Transportation Costs	Estimated 2015 Combined PCB Transportation and Destruction Costs
Contamination > 2 PPM for oil and >50 PPM for other	$30,000	$2,000	$7,000	$39,000

Table 34 - Estimated Cost of PCB Waste Transportation and Destruction in 2015 (ii)

Estimated cost of replacing 23 PCB transformers (i)	$138,000
Estimated cost of transporting and destroying PCB waste(ii)	$39,000
Estimated total to replace 23 transformers, transport and destroy PCB material for the year 2015	$177,000

Table 35 - Estimated Cost of 2015 PCB Activities

ESTIMATED COST OF COMPLIANCE 2016

10% (23) of the 233 transformers identified as >50 PPM PCB will be replaced in 2016.

	Estimated Number of Transformers Replaced (pole top and pad mount)	Estimated 2016 Capital Transformer Cost	Estimated 2016 OM&A Cost to Replace the Transformers	Estimated 2016 Combined OM&A and Capital Costs
Transformers >50 PPM PCB	23	--	--	$138,000

Table 36 - Estimated Cost of OM&A and Capital PCB Transformer Replacements in 2016 (i)

	Estimated 2013 >2 PCB Oil Destruction Costs	Estimated 2016 Solid PCB Waste Destruction Costs	Estimated 2016 PCB Oil and Solid Waste Transportation Costs	Estimated 2016 Combined PCB Transportation and Destruction Costs
Contamination > 2 PPM for oil and >50 PPM for other	$30,000	$2,000	$7,000	$39,000

Table 37 - Estimated Cost of PCB Waste Transportation and Destruction in 2016 (ii)

Estimated cost of replacing 23 PCB transformers (i)	$138,000
Estimated cost of transporting and destroying PCB waste(ii)	$39,000
Estimated total to replace 23 transformers, transport and destroy PCB material for the year 2016	$177,000

Table 38 - Estimated Cost of 2016 PCB Activities

ESTIMATED COST OF COMPLIANCE 2017

10% (23) of the 233 transformers identified as >50 PPM PCB will be replaced in 2017.

	Estimated Number of Transformers Replaced (pole top and pad mount)	Estimated 2017 Capital Transformer Cost	Estimated 2017 OM&A Cost to Replace the Transformers	Estimated 2017 Combined OM&A and Capital Costs
Transformers >50 PPM PCB	23	--	--	$138,000

Table 39 - Estimated Cost of OM&A and Capital PCB Transformer Replacements in 2017 (i)

	Estimated 2017 >2 PCB Oil Destruction Costs	Estimated 2017 Solid PCB Waste Destruction Costs	Estimated 2017 PCB Oil and Solid Waste Transportation Costs	Estimated 2017 Combined PCB Transportation and Destruction Costs
Contamination > 2 PPM for oil and >50 PPM for other	$30,000	$2,000	$7,000	$39,000

Table 40 - Estimated Cost of PCB Waste Transportation and Destruction in 2017 (ii)

Estimated cost of replacing 23 PCB transformers (i)	$138,000
Estimated cost of transporting and destroying PCB waste(ii)	$39,000
Estimated total to replace 23 transformers, transport and destroy PCB material for the year 2017	$177,000

Table 41 - Estimated Cost of 2017 PCB Activities

ESTIMATED COST OF COMPLIANCE 2018

The remaining 17 transformers identified as >50 PPM PCB will be replaced in 2018.

	Estimated Number of Transformers Replaced (pole top and pad mount)	Estimated 2018 Capital Transformer Cost	Estimated 2018 OM&A Cost to Replace the Transformers	Estimated 2018 Combined OM&A and Capital Costs
Transformers >50 PPM PCB	17	--	--	$102,000

Table 42 - Estimated Cost of OM&A and Capital PCB Transformer Replacements in 2018 (i)

	Estimated 2018 >2 PCB Oil Destruction Costs	Estimated 2018 Solid PCB Waste Destruction Costs	Estimated 2018 PCB Oil and Solid Waste Transportation Costs	Estimated 2018 Combined PCB Transportation and Destruction Costs
Contamination > 2 PPM for oil and >50 PPM for other	$29,645.63	$2,000	$7,000	$38,645.63

Table 43 - Estimated Cost of PCB Waste Transportation and Destruction in 2018 (ii)

Estimated cost of replacing 23 PCB transformers (i)	$102,000
Estimated cost of transporting and destroying PCB waste(ii)	$38,645.63
Estimated total to replace 23 transformers, transport and destroy PCB material for the year 2018	$140,645.63

Table 44 - Estimated Cost of 2018 PCB Activities

TOTAL ESTIMATED COST OF COMPLIANCE

Grey shaded area denotes actual expenditures for PCB activities completed for the applicable years

Year	Actual and Anticipated Number of U/G Transformers Replaced	Actual and Anticipated Number of O/H Transformers Replaced	Actual Transformer Replacement OM&A Cost (labour, trucking overheads etc.)	Actual Transformer Replacement Capital Cost	Combined OM&A and Capital Transformer Replacement Cost ($6,000 per transformer)	Actual and Anticipated Oil Destruction Costs for >2 PPM PCB (2011-2018) (2008-2010 TBH only destroyed >50 PPM PCB oil)	Actual and Anticipated Destruction Costs of >50 PPM PCB Solid Waste Material	Actual and Anticipated Transport Costs	Actual and Anticipated Cost Totaled
2009	6	44	$162,206.12	$101,412.28	$263,618.40	$17,913.02	$9,684.59	$8,770.00	$299,986.01
2010	3	23	$121,296.48	$41,908.65	$163,205.13	$6,378.75	$1,248.45	$3,500.00	$174,332.33
2011	12	13	$97,882.08	$59,605.70	$157,487.51	$25,107.75	$1,568.90	$6,241.04	$190,405.47
2012	12	11	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2013	5	18	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2014	0	23	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2015	0	23	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2016	0	23	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2017	0	23	--	--	$138,000	$30,000.00	$2,000.00	$7,000.00	$177,000.00
2018	0	17	--	--	$102,000	$29,645.63	$2,000.00	$7,000.00	$140,645.63
TOTAL									$1,867,369.44

The current plan total incorporates overall program cost actuals for 2009 – 2011 and includes a revised transformer replacement cost of $6,000 vs the original plan amount of $10,000

Using the combined cost totals for 2009, 2010 and 2011 transformers replaced under both OM&A and Capital and the total number transformers replaced in 2009, 2010 and 2011, the 2012 to 2018 anticipated costs for transformer replacement has been revised accordingly to $6,000 per transformer ($584311.31 / 101 transformers = $5785.26 per transformer).

The increased number of transformers replaced in 2009 was due to the revised legislation which mandated all >500 ppm and select >50 ppm PCB transformers be removed from service by the end of 2009

Other Cost Factors to Consider

The above pricing above makes various assumptions for the purpose of estimating. Below are listed some factors that could have a bearing on the accuracy of these estimates.

Additional Costs

- TBH is scheduled to complete its pad mount PCB transformer replacement program in 2012, which will likely reduce the overall individual component replacement cost as pole top equipment is cheaper than the pad mounted equipment – those changes will be incorporated into this plan and communicated to finance once determined through a full year of only completing pole top replacements
- Due to local contractors not being able to pick up 2 – 50 PPM oil because of regulatory constraints in 2011, TBH will be forced to include this lower level PCB oil waste in with the volume of waste oil provided to the destruction company - TBH will manage the storage of this oil in within the East / West tanks accordingly so they will pay a reduced cost for the oil picked up, shipped and processed.
- Transportation costs through 2012 have been increased to $7000 to reflect additional waste pick up requests based on the extra oil waste accumulating as per the above text.

- As of May 2012, due to approximately three additional >50 PPM PCB transformers being removed from service annually due to (capital construction activities, equipment failures, motor vehicle accidents etc.) the PCB management plan has progressed ahead of schedule as only 159 of the original 290 >50 PPM PCB transformers remain in service, the plan was modified in 2012 from the original version which had a 2020 completion year to 2018 to reflect a continued commitment to replace 23 transformers annually
- Replacement of the contaminated substation transformers and substation breakers is not detailed as an annual activity as that equipment is part of TBHEDI's 4 kV to 25 kV system wide voltage conversion commitments and due to construction variables may or may occur when projected.
- Decontamination and destruction prices for PCB oil and PCB waste could increase; a 12% PCB material increase cost was seen between 2007 and 2008.
- Changes in the Canadian Environmental Protection Act could shorten the timeframes that we have to comply by changing the deadlines, or they could change the levels of PCB contamination that must be removed and destroyed.
- Labeling previously tested equipment from 2007 and earlier years (more than 2,000 transformers) that remain in service is a requirement of the regulations and represents a substantial investment in TBHEDI staff involvement. This cost was not factored in to this plan.
- The cost of inflation for services and material were not taken into account for the purpose of estimating the cost of this sampling campaign.

Cost Savings

- Rather than paying to have transformers contaminated at less than 50 PPM destroyed, TBHEDI presently sells these transformers for scrap to qualifying companies.
- Previously scheduled capital work will also limit the need to schedule the removal of identified PCB transformers as these units will be replaced under the capital funding programs instead operating accounts.

SUMMARY

By implementing this PCB Management Plan TBHEDI will have initiated a mechanism to comply with the Canadian Environmental Protection Act 1999 and the latest proposals regulating the continued use, storage and destruction of PCBs.

This plan identifies the decommissioning, labeling and record keeping required to be able to properly manage PCB contaminated equipment in service and in storage.

It outlines a scheduled approach to removing this equipment from service, eliminating it from storage and the budget requirements necessary to ensure it happens.

As revised in 2012, TBHEDI will have to spend approximately 1.2 million dollars over the next seven years to be in compliance with the present PCB legislation, this figure does not take into account any annual cost of transportation or destruction service increases.

The cost of compliance will be expensive, but not as expensive as the potential risks to the environment should PCB's be allowed to remain in service. It is with this mindset that TBHEDI will assert all necessary resources to achieve this goal.

Internet Resource Links

Department of Justice Canada

Canadian Environmental Protection Act, 1999 . . .

Chlorobiphenyls Regulations (SOR/91-152)

http://laws.justice.gc.ca/en/C-15.31/SOR-91-152/index.html

Storage of PCB Material Regulations (SOR/92-507)

http://laws.justice.gc.ca/en/C-15.31/SOR-92-507/index.html

Federal Mobile PCB Treatment and Destruction Regulations (SOR/90-5)

http://laws.justice.gc.ca/en/C-15.31/SOR-90-5/index.html

PCB Waste Export Regulations, 1996 (SOR/97-109)

http://laws.justice.gc.ca/en/C-15.31/SOR-97-109/index.html

Environment Canada – Waste Management

http://www.ec.gc.ca/wmd-dgd/default.asp?lang=En&n=7D851240-1

Environment Canada – Proposed Regulations

Proposed PCB Regulations

http://www.ec.gc.ca/CEPARegistry/regulations/detailReg.cfm?intReg=105

SECTION 4: TBHEDI UNDERGROUND ASSET RENEWAL PROGRAM

INTRODUCTION

The TBHEDI underground distribution network consists of underground cables, pad mounted transformers, and switching assets. Based on condition assessments and the events of the cable testing program, TBHEDI has determined that its greatest risk lies with the potential failure of substantially aged, heavily loaded arterial cable sections. In addition to the risk associated with arterial cable sections, TBHEDI also acknowledges the elevated risk associated with aged subdivision networks as a whole which may contain unacceptably long service loops, brittle load break elbows (which often fail upon operation), and a number of splices due to past mechanical or electrical damage.

For the purposes of efficiency and customer convenience, it is TBHEDI's intention to systematically rebuild subdivision networks as a whole as they approach end of life however, in the near term (3 year horizon) TBHEDI intends to target the replacement of its most heavily aged underground conductors based on projected customer impact should they be allowed to fail. The intent of this strategy is to limit customer exposure to long term/high impact outages, reduce the cost of inevitable asset replacements by conducting them on regular time where possible rather than as emergency conditions dictate, and enable forecasted budgeting of asset replacements rather than reactionary expenditure in the case of uncontrolled failure.

OBJECTIVE

Presently, the average age of the TBHEDI underground primary cable population is 25 years. The TBHEDI underground cable population is largely XLPE with roughly half of that population being directly buried while the remaining half is encased in duct. The Kinetrics report[35] estimates a typical useful life for direct buried and ducted non-tree retardant XLPE to be 25 years. Based on its own experience, TBHEDI has assumed a

[35] "Asset Depreciation Study for the Ontario Energy Board", conducted by Kinetrics, July 8, 2010.

conservative typical useful life of 35 years[36] for the purpose of mid to long range capital replacement rates.

TBHEDI's long term goal is to adopt a sustainment level of replacement for the underground distribution assets.

[36] TBHEDI assumes a typical useful life for ducted primary cables and directly buried cables to be 40 years and 30 years respectively. The TBHEDI underground cable population is distributed roughly half to each configuration and as such, the average age of 35 years has been assumed.

STRATEGY

As at June 2012, TBHEDI's 416km of underground primary conductor has an estimated average age of 26.2 years. This is primarily due to the proliferation of underground installations in the mid to late 70s (refer to Figure 36).

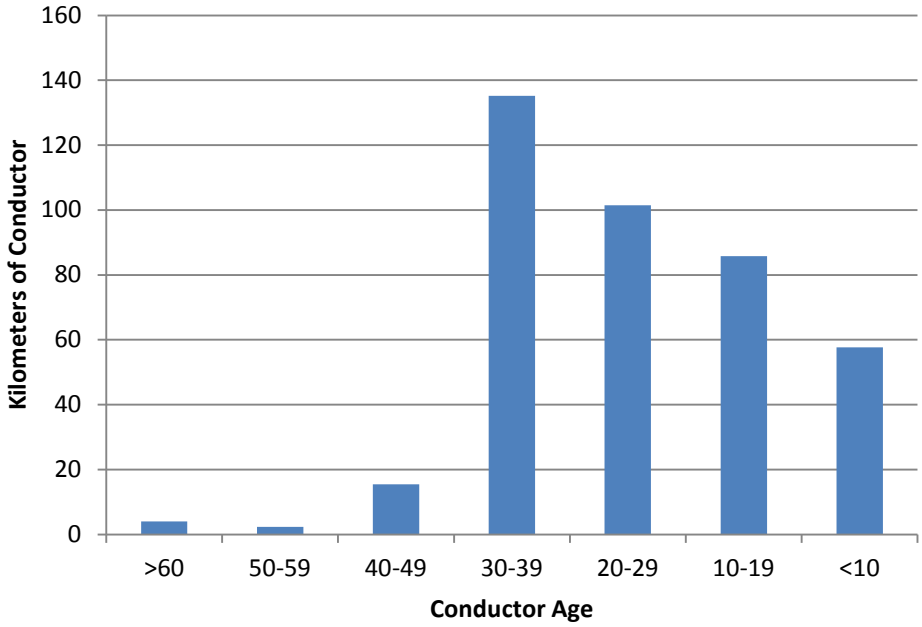

Figure 36 - TBHEDI Underground Conductor Demographic Histogram

In order to achieve a sustainable underground distribution network, one in which network assets are allowed to remain in service for their entire useful life while being replaced before their age related degradation causes them to become a liability, TBHEDI must accelerate its annual replacement rates at a manageable gradient until the average age of the asset population reaches the mid-point of the typical useful life of that asset class. In the case of underground network conductors, which are typically non-tree retardant XLPE, TBHEDI has targeted an average age of 17.5years. TBHEDI believes that a reasonable timeframe for the achievement of this target is 20 years, beginning in 2013.

In order to ensure a replacement effort that considers not only conductor age but also the greatest returns in risk mitigation, TBHEDI has determined its prioritization of underground network assets in the near term (3 years) to be based upon the product of

customers downstream of the conductor/circuit and aggregate load of the downstream customers. The resulting priority list is then sorted by age and ranking in accordance with the TBHEDI Project Ranking Criteria (Table 60). The final project manifest is generated through interdepartmental (engineering, operations, construction) collaboration.

Criteria	Min Score	Min Criteria Description	Max Score	Max Criteria Description
Prudence of Expense	0	Where there is uncertainty whether the regulator will support or interveners will reasonably question the project's requirements the project shall receive the minimum score	15	Where the project is driven by legislative or regulatory compliance requirements or the assets are clearly necessary to supply customers, the project shall receive the maximum score
Public Safety	0	Where the project will have no impact on public safety the project shall receive the minimum score	15	Where the project is likely to reduce a single public injury once every 10 years, the project shall receive the maximum score
Worker Safety	0	Where the project will have no impact on worker safety the project shall receive the minimum score	15	Where the project is likely to reduce a single worker injury once every 10 years, the project shall receive the maximum score
Environmental	0	Where the project will have no impact on the reduction of environmental risk, the project shall receive the minimum score	10	Where the project is likely to eliminate a single environmental incident once every 10 years, the project shall receive the maximum score Note: Additional consideration will be given to system losses.
Reliability	0	Where the project will have no impact on system reliability, the project shall receive the minimum score	10	Where the project is likely to eliminate a single system 4 hr outage to at least 1,000 customers once a year, the project shall receive the

Criteria	Min Score	Min Criteria Description	Max Score	Max Criteria Description
				maximum score. Note: Additional consideration to be given to multiple outage situations.
Power Quality	0	Where the project will have no impact on voltage, the project shall receive the minimum score	5	Where the project will correct existing voltage concerns or problems of 200 or more customers, the project shall receive the maximum score. Note: Consideration also to be given to size of customers affected and the severity of the impact on the customer.
Customer Perception	0	Where the project will have no perceived value to the public at large, the project	10	Where the project will be perceived as an improvement to the system or community by 1,000 or more customers, the project shall receive the maximum score
Maintainability	0	Where maintenance workers will see no improvement in the maintainability of the system, the project shall receive the minimum score	5	Where maintenance workers will clearly perceive a substantial improvement in the maintainability of the system, the project shall receive the maximum score
Operability	0	Where operations staff will see no improvement in the operability of the system, the project shall receive the minimum score	5	Where operations staff will clearly perceive a substantial improvement in the operability of the system, the project shall receive the maximum score
Totals:	**0**	**Minimum Possible**	**100**	**Maximum Possible**

Table 45 - TBHEDI Project Ranking Criteria

Following the initial 3 years of critical underground conductor replacement, TBHEDI will begin concentration on reconstruction of entire subdivisions thereby mitigating the risk

associated with the parallel ageing of the pad mounted distribution transformer population (Figure 37) and associated components.

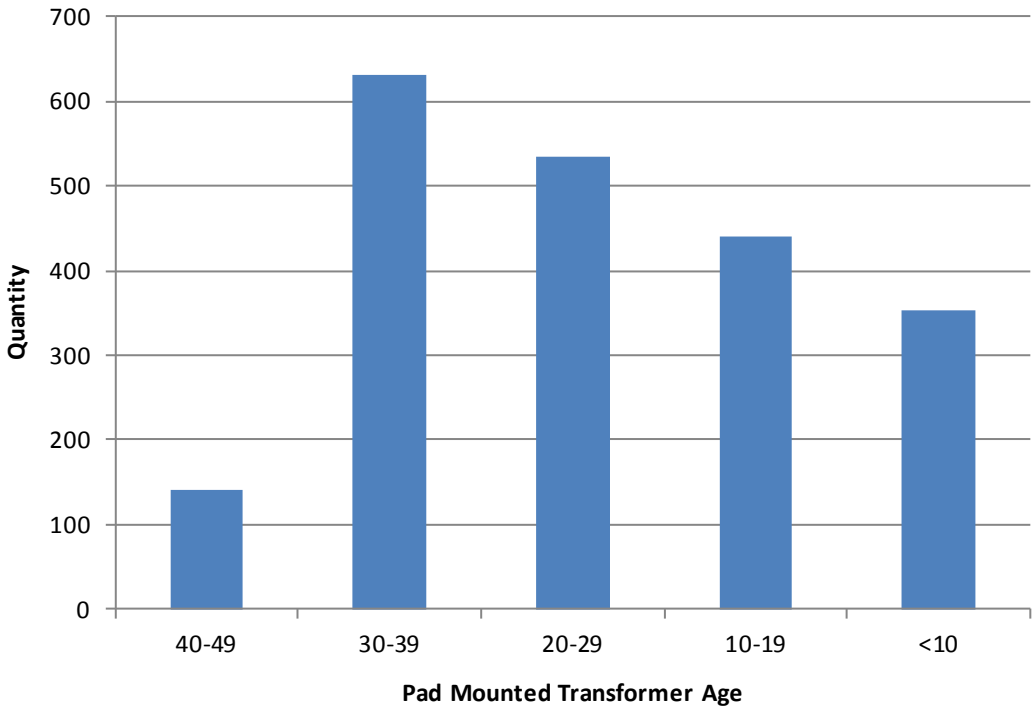

Figure 37 - TBHEDI Pad Mounted Transformer Age Distribution Histogram (Average Age: 23.7 Years, TUL: 40 Years, Target Average: 20 Years)

Once the stable demographic, represented by an average age at the mid-point of the typical useful life, is reached TBHEDI must maintain a replacement rate of 11.9km of underground conductor per year (416km/35 Years) however, given the presently skewed average age, an escalated replacement gradient must be applied.

The TBHEDI underground network conductor population is installed as follows:

Installation Type	Km of Asset	Percent of Total Conductor Length
Three Circuits/Trench (9 Conductors)	0.12	0.26%
Two Circuits/Trench	0.78	1.13%
Once Circuit/Trench	90.32	65.10%
Single Phase/Trench	139.3	33.48%

Table 46 - TBHEDI Underground Network Cable Installation Configuration

Based on the data from Table 61, the average underground network cable installation consists of 2.37 conductors. Given this distribution, the sustainment rate of replacement is considered to be 5km of typical TBHEDI underground network installation per year (11.9km/2.37). For the purposes of developing the underground network capital replacement gradient, it is assumed that the average age of the conductor being replaced as a part of this strategy is 35 years (allowing that in some cases the conductor may be older than this and in others the age may be less).

Given the assumptions and considerations from above, TBHEDI developed a model where underground network assets are replaced at a continually accelerating rate while the underground assets, which remain in service, continue to age at a linear rate. The resulting outcome of this analysis and targeted underground replacement gradient is found in Figure 38. It should be noted that the lack of replacement investment in 2012 was due to the allocation of funds to the underground cable partial discharge testing program. Cable failures which occurred during this testing program will be replaced in 2012/2013.

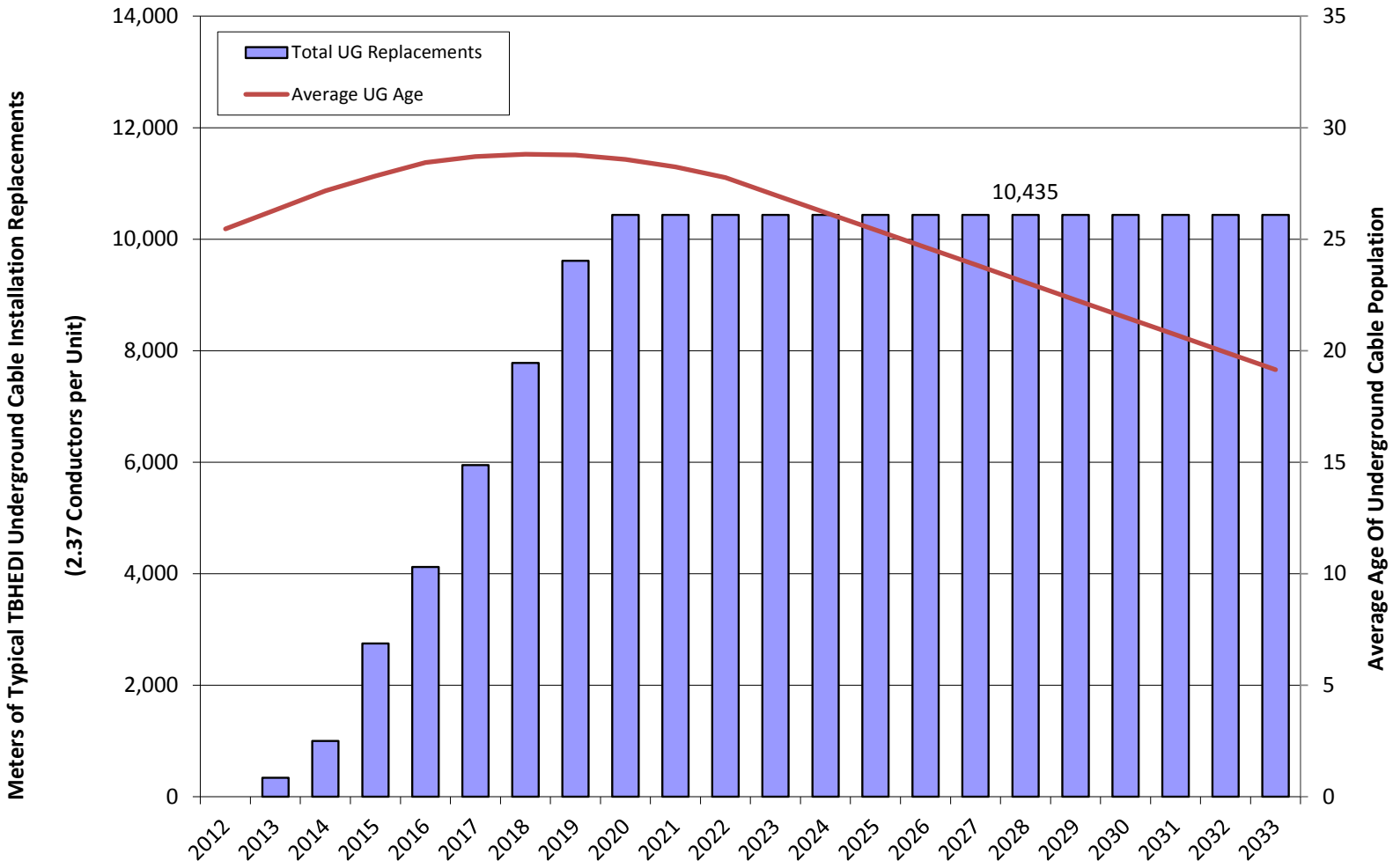

Figure 38 - TBHEDI Underground Cable Replacement Gradient (By Year)

BUDGET FORECAST

The TBHEDI underground network infrastructure replacement cost allocation is as follows (this cost includes typical transformer and switching asset costs per unit length):

Installation Type	Km of Asset	Estimated Replacement Cost Per Unit ($000/km)	TBHEDI Replacement Cost ($000,000)
Three Circuits/Trench (9 Conductors)	0.12	$728	$ 0.087
Two Circuits/Trench	0.78	$600	$ 0.468
Once Circuit/Trench	90.32	$500	$ 45.16
Single Phase/Trench	139.3	$300	$ 41.79
Total Underground Infrastructure Replacement Cost			$ 87.51

Table 47 - TBHEDI Underground Infrastructure Replacement Costs

Based on linear interpolation of Table 62, the estimated cost of the average kilometer of TBHEDI underground network installation (2.37 conductors) is $437,000. Using this per unit cost, the projected annual budget of the TBHEDI Underground Asset Renewal Program is as shown in Table 63.

Year	U/G Replacement Costs	Year	U/G Replacement Costs
2012	$0	2023	$4,560,000
2013	$141,119	2024	$4,560,000
2014	$480,000	2025	$4,560,000
2015	$1,200,000	2026	$4,560,000
2016	$1,800,000	2027	$4,560,000
2017	$2,600,000	2028	$4,560,000
2018	$3,400,000	2029	$4,560,000
2019	$4,200,000	2030	$4,560,000
2020	$4,560,000	2031	$4,560,000
2021	$4,560,000	2032	$4,560,000
2022	$4,560,000	2033	$4,560,000

Table 48 - Underground Asset Renewal Projected Budget Over 20 Years

TARGETED PROGRAM OUTCOMES

The objective of the Underground Asset Renewal Program is to halt the steadily increasing average age of the underground asset population and replace assets at a rate such that the average age becomes stabilized at the mid-point of the typical useful life (17.5 years).

Given the assumptions above, and the replacement rate proposed, the average age of TBHEDI's primary underground network conductors will be 19 years by 2033 (the 20th year of the program). Once the sustainment average of 17.5 years is achieved, TBHEDI will de-escalate replacement efforts to the long term replacement rate of 5km per year (of the average 2.37 conductors per installation) at an ongoing cost of $2.2M/year.

SECTION 5: 12kV DISTRIBUTION STATION REFURBISHMENT

INTRODUCTION

TBHEDI owns and operates four 12kV distribution substations. In addition to providing service to approximately 3,400 rural customers, this network (specifically feeder 36F2, Mapleward Substation) also supports the 3.2MW Mapleward Renewable Generating Station[37]. TBHEDI currently has no intention of retiring the 12kV voltage class and as such, the 12kV infrastructure must be maintained in a sustainable manner.

Capital replacement planning related to 12kV overhead lines, poles, and associated components is discussed in Section 6. The remaining 12kV substation assets will either be replaced on an as needed/run to failure basis or, in the case of the substation power transformer(s), scheduled for replacement based on the TBHEDI risk index classification[38].

The present 12kV substation power transformer demographics and risk index classifications are as follows;

Substation	Transformer	Age	TBHEDI Risk Classification
Mapleward	36T1W	45	3.1
Mapleward	36T1B	45	3.1
Mapleward	36T1R	45	3.1
Alice	23T1	41	3.5
Broadway	19T1	33	2.5
Balsam	18T2	41	2.9

Table 49 - TBHEDI 12kV Power Transformer Demographic

[37] A landfill gas utilization facility contracted under the Renewable Energy Standard Offer Program.

[38] For further details on TBHEDI's risk index classification, refer to SECTION 1: TBHEDI ASSET CONDITION ASSESSMENT

OBJECTIVE

TBHEDI acknowledges that a catastrophic power transformer failure on the 12kV network would cause substantial inconvenience, lost revenue, and potential health and safety risk to its customers. Furthermore, failure to provide an anticipatory budget for the replacement of these assets will result in a significant unplanned capital expense not already accounted for in TBHEDI's rate strategy.

TBHEDI's objective is to plan for capital replacement of the 12kV substation power transformers such that the asset is replaced in a timely manner, prior to failure yet at the perceived end of useful life.

STRATEGY

The TBHEDI risk mitigation strategy encourages replacement of power transformers once they have reached 45 years of life[39] (or beyond) and display evidence of internal component breakdown (as evidenced by visual inspections and oil analysis results).

With the exception of Alice Ave. Substation (Station 23), the 12kV substation transformer population is of reasonable health and is, in general, showing a certain degree of age related degradation (repairable gasket / seal leakage, limited paper / cellulose breakdown, external rusting tank, etc.).

The constant presence of acetylene in transformer 23T1 is indicative of arcing activity within the transformer windings. TBHEDI is proceeding with a 6 month oil testing / analysis schedule for this unit.

In addition to the standard drivers for capital replacement (age related breakdown, and event related breakdown) the Mapleward Substation transformers are also ill suited to perform their function due to the technical limitation of having a manufactured primary voltage (22kV) which is approaching incompatibility with the TBHEDI distribution network

[39] "Asset Depreciation Study for the Ontario Energy Board", conducted by Kinetrics, July 8, 2010.

as efforts are being made to elevate the standard system voltage to 25kV primary (originally 23.5kv and presently 24.1kV). The voltage elevation strategy is in an effort to approach standardized distribution transformer tap requirements while also reducing network losses. The presence of the 3.2MW generation facility on the 36F2 feeder further aggravates the problem of an elevated rural supply voltage. TBHEDI intends to replace the three single phase power transformers at Mapleward Substation with a single three phase power transformer with a more appropriate primary voltage rating and increased power output capability.

Given the above conditions, the TBHEDI 12kV power transformer replacement schedule is as follows;

Substation	Transformer	Budgeted Replacement Year	Age of Transformer in Replacement Year	TBHEDI Risk Classification Upon Replacement*
Mapleward	36T1W	2017	51	3.1
Mapleward	36T1B	2017	51	3.1
Mapleward	36T1R	2017	51	3.1
Alice	23T1	2019	48	3.8
Broadway	19T1	2029	50	3.1
Balsam	18T2	2022	51	3.1

*Predicted risk classification assumes no additional internal breakdown and accounts only for increase in age.

Table 50 - TBHEDI 12kV Power Transformer Replacement Schedule

BUDGET FORECAST

For budgetary purposes, the cost of a 12kV substation power transformer replacement is estimated to be $500,000 with the breakdown as follows;

Component/Activity	Estimated Cost
6MVA, 24.94kV/12.47kV Oil Immersed Power Transformer:	$200,000
Civil Work (i.e. Foundation construction, reconfiguration of steel structure):	$100,000
Engineering and Design:	$50,000
Labour, Trucking, and Additional Materials (i.e. Conductors, insulators, etc.):	$150,000
Estimate Total:	$500,000

Table 51 - 12kV Substation Power Transformer Replacement Cost Estimate

The projected budget is as follows;

Substation	Transformer Replacement Year	Cost Estimate
Mapleward DS	2017	$500,000
Alice DS	2019	$500,000
Balsam DS	2022	$500,000
Broadway DS	2029	$500,000
	Estimated Total:	$2,000,000

Table 52 - 12kV Substation Power Transformer Program Budget

TARGETED PROGRAM OUTCOMES

The intention of the power transformer replacement effort is to mitigate the tangible and intangible costs associated with the unplanned failure of a 12kV substation power transformer. While failure prediction is an inexact science, TBHEDI will continue to perform routine inspections and oil analysis to determine the exact year for optimal replacement of the asset. In the near term however, TBHEDI believes that budgeting for the replacement of these facilities is prudent and intends to review the target year for their replacement annually while anticipating that the Mapleward and Alice Substation replacements will take place on or very near to those years documented here.

SECTION 6: ABOVE GROUND ASSET RENEWAL AND VOLTAGE CONVERSION PROGRAM

INTRODUCTION

The TBHEDI overhead distribution network consists of overhead conductors, distribution transformers, poles, associated framing/guying infrastructure, reclosers and switching assets. Based on condition assessments and asset demographic studies, TBHEDI has determined that its greatest risk lies with the potential failure of substantially aged assets (particularly the structural components), the questionable adequacy of legacy construction practices, and the approaching end of life of the 4kV substation assets.

For the purposes of efficiency (operational and economic) and customer convenience, it is TBHEDI's intention to systematically rebuild and restore the overhead distribution network by targeting bulk zones of depreciated assets for replacement or restoration where possible. Selection of projects is based upon TBHEDI's established Capital Project ranking criteria in conjunction with TBHEDI's developing vision for the ultimate state of the distribution network.

The intent of this program is to limit customer exposure to avoidable outages due to asset failure, ensuring the safety of staff and/or the public, maintain or enhance reliability metrics where possible, limit or eliminate operational or maintenance liabilities, and enable forecasted budgeting of asset replacements rather than reactionary expenditures in the case of uncontrolled failures.

OBJECTIVE

TBHEDI believes that the wood utility pole's lifespan represents the critical path to degradation for the overhead asset population. Presently, the average age of the TBHEDI wood pole population numbering approximately 20,000 poles is 32 years. The Kinetrics report[40] estimates a typical useful life for this asset class to be 40 years.

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[40] "Asset Depreciation Study for the Ontario Energy Board", conducted by Kinetrics, July 8, 2010.

TBHEDI's long term goal is to adopt a sustainment level of replacement for the overhead asset population.

STRATEGY

As at June 2012, TBHEDI's pole population has an estimated age distribution as shown in Figure 39.

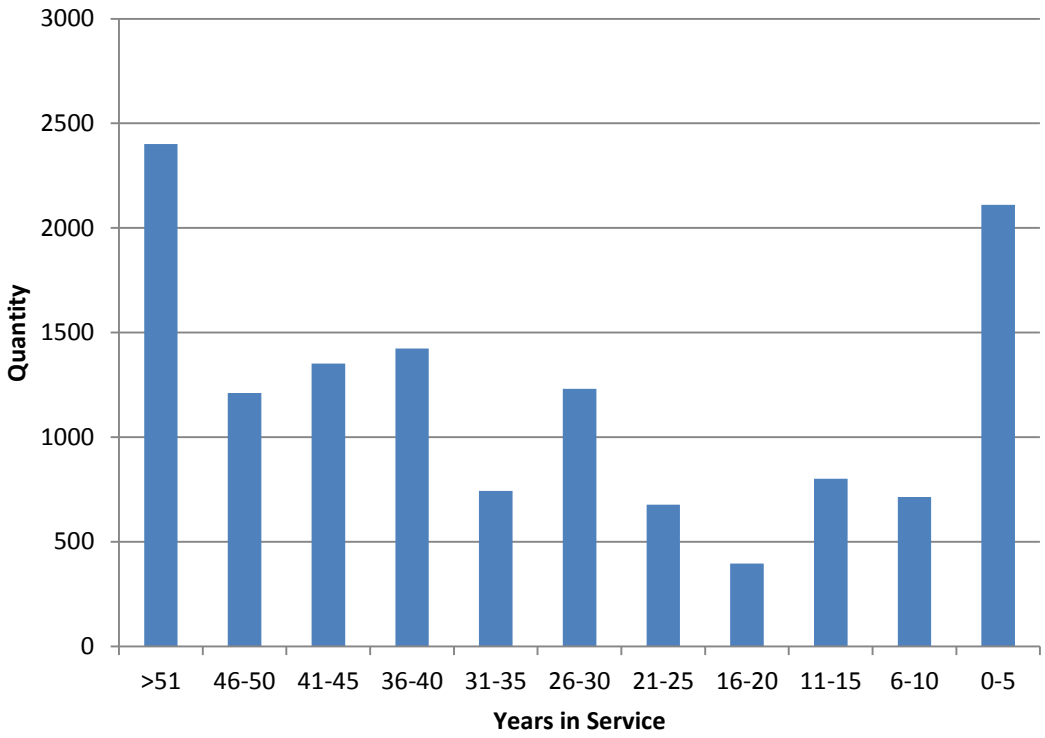

Figure 39 - TBHEDI Wood Pole Demographic Histogram

In order to achieve a sustainable overhead distribution network, one in which assets are allowed to remain in service for their entire useful life while being replaced before their age related degradation causes them to become a liability, TBHEDI must accelerate its annual pole replacement rates at a manageable gradient until the average age of the asset population reaches the mid-point of the typical useful life of that asset class. In the case of the wood pole population, TBHEDI has targeted an annual average age of 20 years. TBHEDI believes that a reasonable timeframe for the achievement of this target is 20 years beginning in 2013.

TBHEDI's most heavily aged poles are not entirely associated with a specific geographic domain however; they are generally more heavily concentrated in the 4kV sub-network (Figure 40).

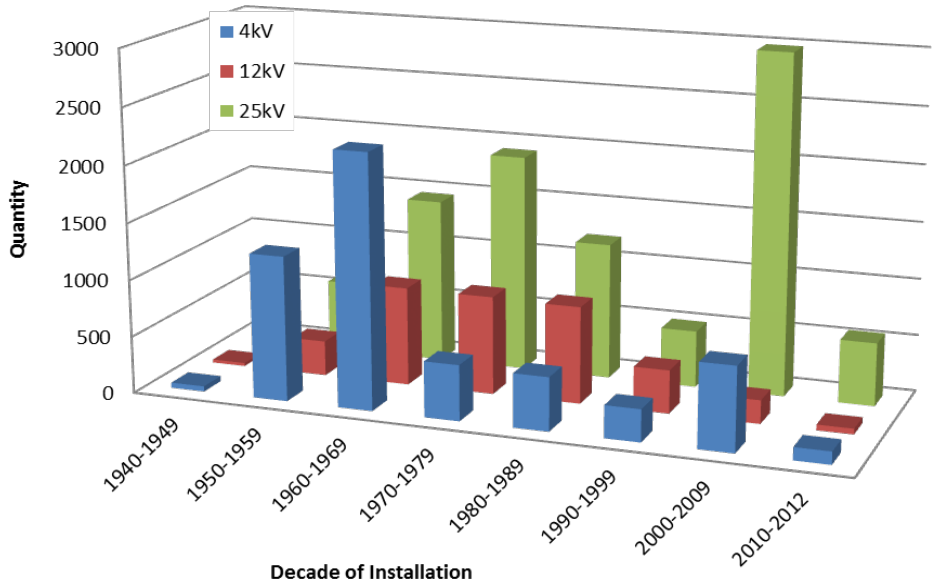

Figure 40 - Pole Age by Voltage Class[41]

Voltage Class	Average Age of Pole Population
4kV	39.9 Years
12kV	35.8 Years
25kV	25.9 Years

Table 53 - Average Age of Pole Population by Voltage Class[32]

Due to the substantial ageing of the 4kV asset population and the inherent efficiencies gained in the execution of such a project, TBHEDI is proceeding with a complete conversion of the 4kV sub-network to a standardized, 25kV primary system. In order to

[41] Note that for Figure 40 and Table 68 where a pole carries more than one voltage class it has been counted once in each class represented. As such, the sum total of the quantities shown in Figure 40 cannot be treated as individual poles but rather as occurrences of voltage classes per pole.

also address heavily aged assets which fall outside of the scope of the annual conversions, TBHEDI will continue to conduct suspect pole replacements on a 'concern' driven basis. Over the past three years, suspect pole changes driven by concerns have averaged 120 units per year.

4kV Conversion Drivers

In addition to the overall age of the 4kV distributed assets, the 4kV conversion initiative is also driven by the economics of the following;

- Replacement of the substantially aged 4kV distribution substation assets;
- Ongoing costs associated with the maintenance of the 4kV distribution substation assets; and,
- Distribution system losses associated with the 4kV sub-network.
- The incremental cost of erecting, stringing and framing a pole which supports 25kV distribution vs. 4kV distribution is negligible.

4kV Distribution Station Investments

TBHEDI's 4kV distribution network depends on 14 substations to step down the 25kV primary to 4kV secondary. TBHEDI inspects each of these facilities monthly and performs maintenance as required.

The average age of TBHEDI's 4kV substation transformers and substation breakers are both 53.8 years. The Kinetrics report[42] estimates a typical useful life for each of these assets to be 45 years and a maximum useful life to be 60 and 65 years respectively. As such, TBHEDI can expect to replace a significant portion of these assets within the next

[42] "Asset Depreciation Study for the Ontario Energy Board", conducted by Kinetrics, July 8, 2010.

10 years. The approximate replacement cost of a 4kV substation and all associated components, less contingency and overheads, is as follows (Table 69);

Distribution Station Component	Estimated Cost
4MVA, 24.94kV/4.16kV, Oil Immersed Power Transformer (Qty 2)	$250,000
4kV, 1200A Breaker Lineup (8 Breakers/Substation Average)	$310,000
DC Supply Components	$20,000
Power and Instrument Transformers	$28,000
Protective Relays	$17,000
Ground & Test Device	$55,000
Power Quality Meters	$25,000
Current Transformers	$20,000
Infrared Viewing Ports	$25,000
Auxiliary Substation Components	$15,000
Civil Work	$200,000
Engineering and Design	$100,000
Labour, Trucking, and Additional Materials	$225,000
Total:	$1,270,000

Table 54 - Estimated TBHEDI Cost to Rebuild One 4kV Substation

Assuming a major substation rebuild takes place annually every year from 2013-2027, the net present cost to TBHEDI represented by these replacements (at a 2% CPI[43]) is $15.4M.

Rather than replacing these assets, TBHEDI will decommission the 4kV substation assets as their associated areas are converted.

The costs associated with all of the decommissioning and subsequent demolition activities for the 4 kV substations will be captured within the specific substation OM&A accounts. As the 4 kV substations have differing configurations and civil infrastructure (some have buildings some do not, some have 1 transformer while others have 2 transformers etc.) the individual substation cost for decommissioning and demolishing

[43] CPI: Consumer Pricing Index

will differ substantially. Detailed below is the anticipated preparation and demolition costs in today's dollars for each substation without contingency or overheads applied

Substation	Subtotal
Mary Street	$56,000
Brock Street	$32,000
McPherson Avenue	$26,000
Balsam Street	$5,500
Windemere Avenue	$56,000
Hardisty Street	$32,000
Vickers Street	$25,000
High Street	$7,000
Grenville Avenue	$50,000
Camelot Street	$85,000
Algoma Street	$55,000
MacDonnell Street	$56,000
Mountdale Avenue	$26,000
Donald Street	$55,000
Combined Overall Total:	$566,500
Average 4kV Substation Decommissioning Cost:	$40,464

Thunder Bay Hydro staff and speciality service contractors will be utilized to complete select activities as required at each of the substations. The activities are listed below;

Thunder Bay Hydro staff will be used to:

- isolate and de-energize all sources of AC power,
- remove all batteries,
- remove any >2 ppm PCB oil,
- remove any >2 ppm PCB equipment
- remove any equipment that can be utilized again

Specialty Service Contractors will be used for:

- asbestos containing material (ACM) abatement
- lead paint sampling and laboratory analysis
- lead paint abatement (if required)
- crane services for hoisting
- haulage or transportation services
- civil works demolition and site reclamation services
- neighbour information package delivery services

Assuming the average substation decommissioning cost of $40,464, the net present value for these activities (assuming the same schedule and CPI as above) is $489,867. Therefore, in terms of only capital replacement costs, conversion of the 4kV and subsequent decommissioning of the substations represents an estimated cost savings of $14.9M over 14 years.

4kV Distribution Station Maintenance Costs

TBHEDI performs a visual inspection of all substations monthly and a detailed inspection of all substations every three years. This regime includes regular inspection and maintenance of the following facilities as their conditions require;

- Substation enclosure and fencing;
- Breakers and switchgear;
- Power transformers; and,
- Auxiliary station equipment (AC and DC systems, protective relaying, SCADA equipment, , remote terminal units, metering, instrument transformers, lightning arrestors, insulators, bus connections, steel structures, foundations, oil containment, ducts / conduits etc.).

The substation maintenance regime also includes event related maintenance due to faults or component failure, for the purposes of this section the costs for these activities are distributed across the 4kV substation population.

TBHEDI's annual costs associated with the scheduled and emergency maintenance of the 4kV substation population is estimated to be $14,610 per station, per year ($204,540 total per year).

Assuming that TBHEDI will decommission one substation per year from 2013-2027, the net present value of the deferred maintenance cost associated with the 4kV substations is approximately $7.5M (assumes 13 stations remain in 2013, 12 in 2014, and so on).

4 kV System Losses

The conductors that are utilized in the distribution network contain a resistive component which dissipates power in the form of heat when supporting electrical loads. Heat dissipated by conductors is a component of electrical loss and represents a monetary loss to the LDC.

Typically, conductors are sized such that they can economically perform the function for which they are designed while limiting the amount of energy lost through heating. Designers must strike a balance whereby losses are minimized and yet the conductor remains economical and practical from a construction perspective.

The power lost to the heating of a conductor is proportional to the square of the current and the resistance of the conductor. Further, the current demanded by an electrical load is proportional to the voltage multiplied by the current. As such, a load connected directly to the 25kv network will have a current demand equivalent to 1/6th that of an equivalent 4kV load.

TBHEDI has performed an analysis of its present system where the losses sustained in the 4kV sub-network are compared to the losses sustained upon conversion of that network to 25kV. The result of this study estimates that the net loss reduction resulting from the voltage conversion (and hence reduced network current) may amount to $500,000 per year, projecting this savings over the same 2013-2027 period as before results in a net present savings of approximately $3.4M.

To summarize, TBHEDI anticipates that the conversion of the 4kV to 25kV as a sub-initiative to the Above Ground Asset Renewal Program will result in a net savings of $25.8M[44] due to deferral of maintenance activities, equipment replacements, and distribution system losses.

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[44] Assuming a CPI of 2%, a 14 year schedule (1 year per substation), and in 2012 dollars

Voltage Conversion Project Selection

TBHEDI has defined 44 independent 4kV to 25kV capital conversion projects. These projects are typically bounded by city streets and encompass a single 4kV feeder. These projects are prioritized by the relative condition of the assets contained within the project boundary, the relative health of the 4kV substation to which the project is associated, their scoring as determined by the TBHEDI Project Ranking Criteria (Table 70) and their impact on the overall connectivity of the 4kV sub-network.

Criteria	Min Score	Min Criteria Description	Max Score	Max Criteria Description
Prudence of Expense	0	Where there is uncertainty whether the regulator will support or interveners will reasonably question the project's requirements the project shall receive the minimum score	15	Where the project is driven by legislative or regulatory compliance requirements or the assets are clearly necessary to supply customers, the project shall receive the maximum score
Public Safety	0	Where the project will have no impact on public safety the project shall receive the minimum score	15	Where the project is likely to reduce a single public injury once every 10 years, the project shall receive the maximum score
Worker Safety	0	Where the project will have no impact on worker safety the project shall receive the minimum score	15	Where the project is likely to reduce a single worker injury once every 10 years, the project shall receive the maximum score
Environmental	0	Where the project will have no impact on the reduction of environmental risk, the project shall receive the minimum score	10	Where the project is likely to eliminate a single environmental incident once every 10 years, the project shall receive the maximum score Note: Additional consideration will be given to system losses.
Reliability	0	Where the project will have no impact on system reliability, the project shall	10	Where the project is likely to eliminate a single system 4 hr outage to at

Criteria	Min Score	Min Criteria Description	Max Score	Max Criteria Description
		receive the minimum score		least 1,000 customers once a year, the project shall receive the maximum score. Note: Additional consideration to be given to multiple outage situations.
Power Quality	0	Where the project will have no impact on voltage, the project shall receive the minimum score	5	Where the project will correct existing voltage concerns or problems of 200 or more customers, the project shall receive the maximum score. Note: Consideration also to be given to size of customers affected and the severity of the impact on the customer.
Customer Perception	0	Where the project will have no perceived value to the public at large, the project	10	Where the project will be perceived as an improvement to the system or community by 1,000 or more customers, the project shall receive the maximum score
Maintainability	0	Where maintenance workers will see no improvement in the maintainability of the system, the project shall receive the minimum score	5	Where maintenance workers will clearly perceive a substantial improvement in the maintainability of the system, the project shall receive the maximum score
Operability	0	Where operations staff will see no improvement in the operability of the system, the project shall receive the minimum score	5	Where operations staff will clearly perceive a substantial improvement in the operability of the system, the project shall receive the maximum score
Totals:	**0**	**Minimum Possible**	**100**	**Maximum Possible**

Table 55 - TBHEDI Project Ranking Criteria

ABOVE GROUND ASSET RENEWAL GRADIENT

Once the stable demographic, represented by an average age at the mid-point of the typical useful life, is reached TBHEDI must maintain a replacement rate of 489 poles per year (19,549/40 Years) however, given the presently skewed average age, an escalated replacement gradient must be applied.

The average age of the poles falling within the 44 capital conversion projects is 39.9 years. The assumed average age of poles replaced as a part of the maintenance regime, or 'concern' driven, is 50 years. In 2012 TBHEDI will replace the equivalent of 448 poles as a part of the capital conversion program and an estimated 100 poles as a part of the maintenance regime (100 poles are assumed rather than 120 due to TBHEDI's intention to shift the maintenance efforts more heavily toward a preventative/predictive maintenance regime). It is assumed that the maintenance replacement rate will remain relatively static since TBHEDI does not intend to dedicate additional resources to this function and, because an accelerated effort made as a part of the capital replacement strategy will address a certain number of poles which may drive concern reports in the near term, the number of annual concern reports generated is expected to also continue at the established rate. It is further assumed that, upon final de-escalation to the overhead asset sustainment level of roughly 490 poles per year, maintenance replacements of poles will reduce substantially as capital resources will be allocated to this function and maintenance crews will further increase their emphasis on preventative and predictive activities.

Given the assumptions and considerations from above, TBHEDI has developed a model whereby the overhead network assets are replaced at a continually accelerating rate while the overhead assets which remain in service continue to age at a linear rate. The resulting outcome of this analysis and targeted overhead replacement gradient is found in Figure 41.

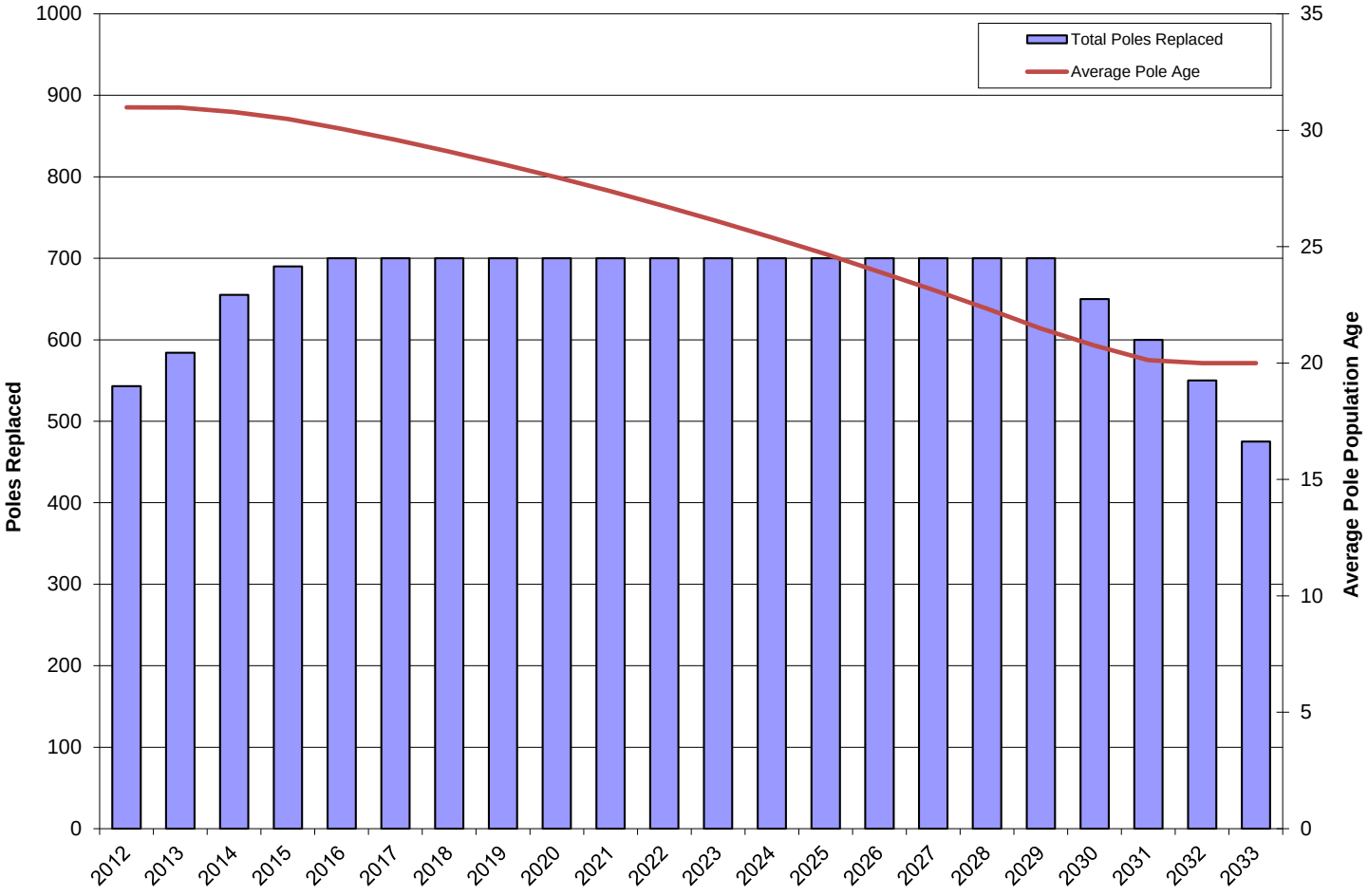

Figure 41 - TBHEDI Above Ground Asset Network Replacement Gradient (By Year)

BUDGET FORECAST

Based on historical capital and maintenance activities, TBHEDI's budgetary estimate for a complete pole replacement (including overhead transformers, overhead switching assets, conductors, framing, and guying associated with the project) is $11,500/pole. Where pad mounted transformers fall within the scope of an overhead voltage conversion project, these assets are replaced with 25kV equivalents at an estimated cost of $35,000 per unit, which includes conductor, excavation, pad, pad mounted switching assets, and associated components. Given these per unit values, the projected annual budget for the TBHEDI Above Ground Asset Renewal Program is as found in Table 71. Note that these values include the contribution of the TBHEDI maintenance replacement activities.

Year	Overhead Asset Replacement Cost	Year	Overhead Asset Replacement Cost
2012	$6,088,073	2023	$8,050,000
2013	$7,232,471	2024	$8,050,000
2014	$8,022,500	2025	$8,050,000
2015	$8,075,000	2026	$8,050,000
2016	$8,335,000	2027	$8,050,000
2017	$8,330,000	2028	$8,050,000
2018	$8,330,000	2029	$8,050,000
2019	$8,330,000	2030	$7,475,000
2020	$8,330,000	2031	$6,900,000
2021	$8,330,000	2032	$6,325,000
2022	$8,050,000	2033	$5,462,500

Table 56 - TBHEDI Forecasted Above Ground Asset Renewal Budget

TARGETED PROGRAM OUTCOMES

The objective of the Overhead Asset Renewal Program is to halt the steadily increasing average age of the overhead asset population and replace assets at a rate such that the

average age becomes stabilized at the mid-point of the typical useful life (20 years). The sub-initiative of the Above Ground Asset Renewal Program is to systematically convert the legacy 4kV sub-network to the standardized 25kV primary voltage.

Given the assumptions above, and the replacement rate proposed, TBHEDI's wood pole population will have an average age of 20 years by 2032 (the 19th year of the program). Upon achievement of the sustainment average, TBHEDI will de-escalate replacement efforts to the long term replacement rate of 490 poles per year at an ongoing cost of $5.46M/year.

Based on the proposed asset replacement rate and the initial capital replacement focus on the voltage conversion, the 4kV sub-network is scheduled to be completely converted by 2024 In this period, the following outcomes will have taken place;

- Complete elimination of the 784 legacy, pole top lag bolt configurations;
- Replacement (or reframing where possible) of approximately 5,200 wood poles (estimated average age as at 2012: 39.9 Years);
- Removal and replacement of approximately 1,464, 4kV overhead distribution transformer (estimated average age as at 2012: 44.7 Years);
- Removal of approximately 87km of 'restricted' conductor; and,
- Decommissioning and site remediation of all fourteen 4kV distribution stations.

SECTION 7: HISTORICAL CAPITAL PROJECTS, 2013-2015 PROJECTS IN DEVELOPMENT, AND PROJECTED CAPITAL BUDGET ENVELOPE

INTRODUCTION

The following tables provide a summary of TBHEDIs historical and projected capital expenditures related to the distribution system assets.

Historical figures are provided for the period from 2009-2011 and expenses are projected in detail for 2012-2015. Finally, long term costs are forecasted in Figure 42.

HISTORICAL CAPITAL PROGRAM BUDGET

YEAR	PROJECT	PROJECT TYPE	ACTUAL
2009	Hyde/Murray	Overhead Voltage Conversion	$103,866
	Mary/Mountdale	Overhead Voltage Conversion	$306,061
	Mary/Ford	Overhead Voltage Conversion	$202,409
	Lily/Donald	Overhead Voltage Conversion	$10,786
	Centre/Francis	Overhead Voltage Conversion	$11,319
	Georgina/Francis	Overhead Voltage Conversion	$8,632
	Montreal/Mountdale	Overhead Voltage Conversion	$5,673
	Hill Street	Overhead Voltage Conversion	$24,108
	Winnipeg Ave	Overhead Voltage Conversion	$1,117,745
	Ray Blvd (PH1)	Overhead Voltage Conversion	$19,158
	10M6 Kam River Crossing	System Improvement	$430,779
	County Park	Underground Network Rebuild/Improvement	$694,972
	Summit/Cornwall	Overhead Voltage Conversion	$655,249
	Ontario/Banning	Overhead Voltage Conversion	$1,254,943
	Unplanned Capital		$224,735
	Wholesale Metering Upgrades		$346,465
	Maintenance Replacements	Maintenance Replacements	$945,523
		Total	**$6,362,424**

Table 57 – 2009 TBHEDI Distribution Asset Capital Replacement Budget

YEAR	PROJECT	PROJECT TYPE	ACTUAL
2010	Hyde/Murray	Overhead Voltage Conversion	$1,067,482
	Mary/Mountdale	Overhead Voltage Conversion	$353,765
	Mary/Ford	Overhead Voltage Conversion	$253,999
	Lily/Donald	Overhead Voltage Conversion	$940,595
	County Fair (PH2)	Underground Network Rebuild/Improvement	$674,962
	College Park (PH1)	Underground Network Rebuild/Improvement	$4,817
	Brock/Ford	Overhead Voltage Conversion	$21,339
	Brock/Syndicate	Overhead Voltage Conversion	$117,634
	Centre/Francis	Overhead Voltage Conversion	$616,238
	Georgina/Francis	Overhead Voltage Conversion	$28,336
	Montreal/Mountdale	Overhead Voltage Conversion	$149,495
	Durban/Brodie	Overhead Voltage Conversion	$20,632
	Brown/Isabella	Overhead Voltage Conversion	$85,158
	Mary/Heath	Overhead Voltage Conversion	$44,570
	Ontario/Banning	Overhead Voltage Conversion	-$2,252
	Unplanned Capital		$72,997
	Wholesale Metering Upgrades		$377,311
	Maintenance Replacements	Maintenance Replacements	$1,148,214
		Total	**$5,975,292**

Table 58 - 2010 TBHEDI Distribution Asset Capital Replacement Budget

YEAR	PROJECT	PROJECT TYPE	ACTUAL
2011	Hyde/Murray	Overhead Voltage Conversion	$12,901
	County Fair (PH2)	Underground Network Rebuild/Improvement	-$4,376
	College Park (PH1)	Underground Network Rebuild/Improvement	$687,439
	Brock/Ford	Overhead Voltage Conversion	$797,109
	Brock/Syndicate	Overhead Voltage Conversion	$1,284,459
	Centre/Francis	Overhead Voltage Conversion	$1,284,691
	Montreal/Mountdale	Overhead Voltage Conversion	$547,092
	Ogden/McMurray	Overhead Voltage Conversion	$19,539
	McKenzie/Dease	Overhead Voltage Conversion	$1,894
	Brunswick/Legion	Overhead Voltage Conversion	$8,583
	Clayte/Buriss	Overhead Voltage Conversion	$17,530
	Huron/Otto	Overhead Voltage Conversion	$12,116
	Dawson/Rockwood	Overhead Voltage Conversion	$406
	Redmond/Egan	Overhead Voltage Conversion	$176
	Balsam/Minot	Overhead Voltage Conversion	$406
	Elm/Campbell	Overhead Voltage Conversion	$176
	Elliott/Leslie	Overhead Voltage Conversion	$406
	Durban/Brodie	Overhead Voltage Conversion	$4,518
	Brown/Isabella	Overhead Voltage Conversion	$927,305
	Mary/Heath	Overhead Voltage Conversion	$9,310
	Unplanned Capital		$29,513
	Maintenance Replacements	Maintenance Replacements	$1,218,846
		Total	**$6,860,039**

Table 59 - 2011 TBHEDI Distribution Asset Capital Replacement Budget

NEAR TERM (2012-2015) & LONG TERM (2016-2033) CAPITAL PROGRAM BUDGET FORECAST

YEAR	PROJECT	PROJECT TYPE	ACTIVITY	PROJECTED COST
2012	Brown/Isabella	Overhead Voltage Conversion	Overhead Construction	$1,616,456
	Brock/Ford	Overhead Voltage Conversion	Overhead Construction	$1,440,500
	Georgina/Francis	Overhead Voltage Conversion	Overhead Construction	$1,096,922
	Ogden/McMurray	Overhead Voltage Conversion	Overhead Construction	$817,776
	Durban/Brodie	Overhead Voltage Conversion	Design	$7,088
	Huron/Otto	Overhead Voltage Conversion	Design	$43,962
	Clayte/Buriss	Overhead Voltage Conversion	Design	$66,710
	Balsam/Minot	Overhead Voltage Conversion	Design	$71,380
	Dawson/Rockwood	Overhead Voltage Conversion	Design	$35,120
	Elliott/Leslie	Overhead Voltage Conversion	Design	$33,640
	Elm/Campbell	Overhead Voltage Conversion	Design	$54,730
	Redmond/Egan	Overhead Voltage Conversion	Design	$63,980
	Brunswick/Legion	Overhead Voltage Conversion	Design	$5,099
	Dacre/Leslie	Overhead Voltage Conversion	Design	$13,818
	MacDougall/Court	Overhead Voltage Conversion	Design	$0
	Unplanned Capital	Unplanned	Unplanned	$68,000
	Underground Cable Testing	Condition Assessment	Underground Cable Testing	$206,061
	Maintenance Replacements	Maintenance	Maintenance Replacements	$1,116,419
	Total			**$6,757,661**
YEAR	**PROJECT**	**PROJECT TYPE**	**ACTIVITY**	**PROJECTED COST**
2013	Durban/Brodie	Overhead Voltage Conversion	Overhead Construction	$803,871
	Mary/Heath	Overhead Voltage Conversion	Overhead Construction	$1,374,452
	Ogden/McMurray	Overhead Voltage Conversion	Overhead Construction	$1,721,369
	Brunswick/Legion	Overhead Voltage Conversion	Overhead Construction	$724,206
	Huron/Otto	Overhead Voltage Conversion	Overhead Construction	$518,443
	Elliott/Leslie	Overhead Voltage Conversion	Overhead Construction	$960,532
	Dacre/Leslie	Overhead Voltage Conversion	Design	$70,717
	Black Bay/Dewe	Overhead Voltage Conversion	Design	$89,342
	McPherson/Christie	Overhead Voltage Conversion	Design	$49,609
	10M3-17M1 Tie	System Imropvement	Underground Construction	$141,119
	Unplanned Capital	Unplanned	Unplanned	$93,275
	Maintenance Replacements	Maintenace	Maintenance Replacements	$1,129,598
	Total			**$7,676,533**

Table 60 - Projected 2012-2013 TBHEDI Distribution Asset Capital Replacement Budget

YEAR	PROJECT	PROJECT TYPE	ACTIVITY	PROJECTED COST
2014	Clayte-Buriss	Overhead Voltage Conversion	Overhead Construction	$2,479,128
	Huron-Otto	Overhead Voltage Conversion	Overhead Construction	$1,011,601
	Dawson-Rockwood	Overhead Voltage Conversion	Overhead Construction	$1,003,348
	Dacre-Leslie	Overhead Voltage Conversion	Overhead Construction	$1,780,526
	Elm-Campbell	Overhead Voltage Conversion	Overhead Construction	$495,600
	Northern-Vickers	Overhead Voltage Conversion	Design	$69,030
	McPherson-Christie	Overhead Voltage Conversion	Design	$42,900
	Isabella-James	Overhead Voltage Conversion	Design	$39,060
	21F6 Rebuild	Overhead Voltage Conversion	Design	$73,710
	21F5 Rebuild	Overhead Voltage Conversion	Design	$15,540
	10M8 Reconfiguration & Reconductoring	Underground Network Rebuild/Improvement	Underground Construction	$480,000
	Unplanned Capital	Unplanned	Unplanned	$100,000
	Maintenance Replacements	Maintenance	Maintenance Replacements	$1,150,000
	Total			**$8,740,443**
YEAR	**PROJECT**	**PROJECT TYPE**	**ACTIVITY**	**PROJECTED COST**
2015	Balsam-Minot	Overhead Voltage Conversion	Overhead Construction	$1,833,345
	Dewe-Rita	Overhead Voltage Conversion	Overhead Construction	$2,568,350
	McKenzie-Dease	Overhead Voltage Conversion	Overhead Construction	$472,306
	Elm-Campbell	Overhead Voltage Conversion	Overhead Construction	$822,517
	Black Bay-Dewe	Overhead Voltage Conversion	Overhead Construction	$831,600
	Redmond-Egan	Overhead Voltage Conversion	Overhead Construction	$394,800
	21F1 Rebuild	Overhead Voltage Conversion	Design	$64,740
	McDougall-Court (PH1&PH2)	Overhead Voltage Conversion	Design	$68,996
	Cumming-Brodie	Overhead Voltage Conversion	Design	$50,310
	Finlayson-Brodie	Overhead Voltage Conversion	Design	$30,030
	Cameron-Vickers	Overhead Voltage Conversion	Design	$25,740
	10M7 Reconfiguration & Reconductoring	Underground Network Rebuild/Improvement	Underground Construction	$707,500
	U/G Replacement	Underground Network Rebuild/Improvement	Underground Construction	$480,000
	Unplanned Capital	Unplanned	Unplanned	$100,000
	Maintenance Replacements	Maintenance	Maintenance Replacements	$1,150,000
	Total			**$9,600,234**

Table 61 - Projected 2014-2015 TBHEDI Distribution Asset Capital Replacement Budget

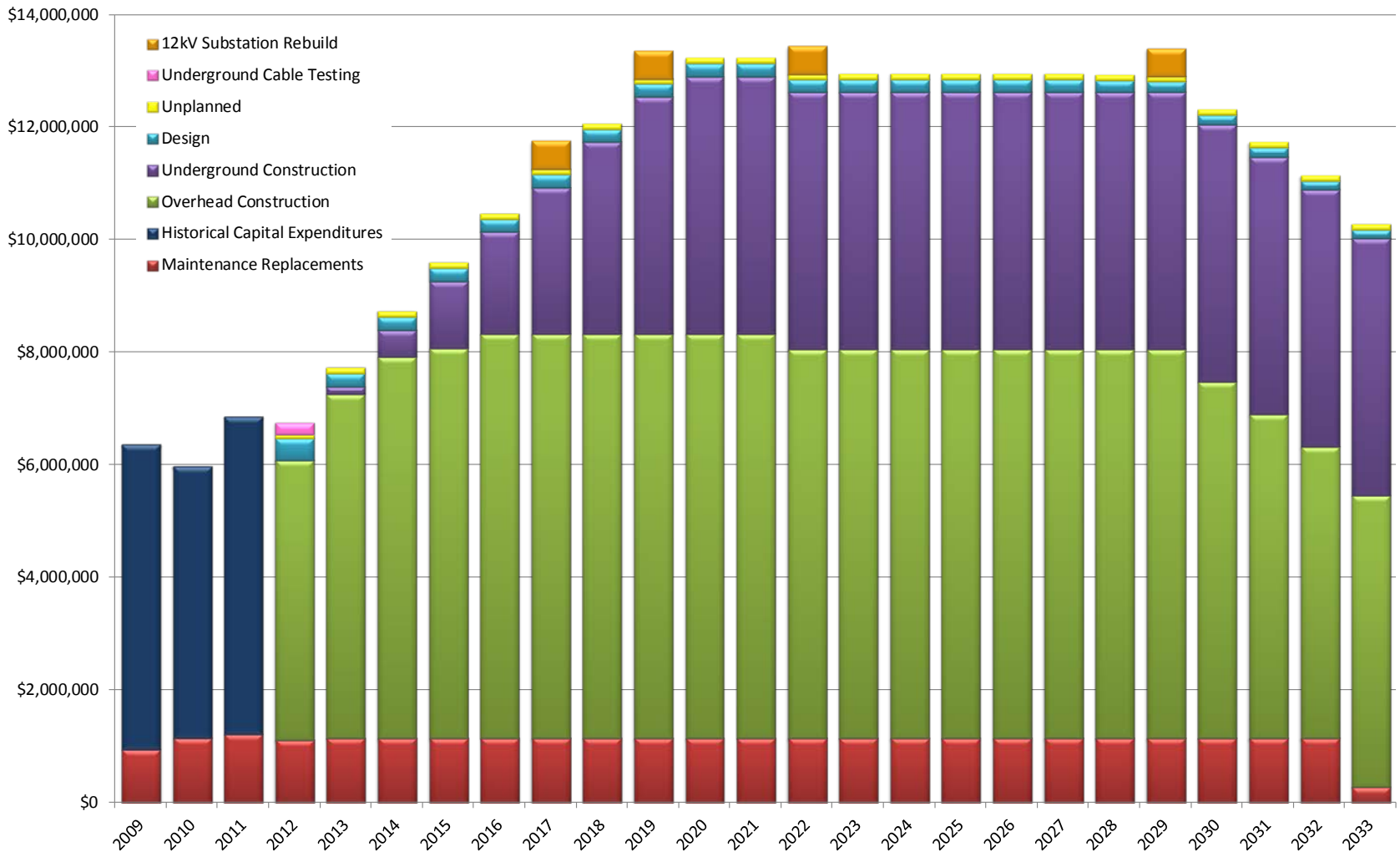

Figure 42 - TBHEDI Projected Distribution Asset Capital Budget Envelope

SECTION 8: LIMITATIONS & FUTURE DEVELOPMENTS IN TBHEDI ASSET MANAGEMENT STRATEGIES

INTRODUCTION

TBHEDI is dedicated to providing a safe, economical, and reliable power supply to the residents and businesses within the City of Thunder Bay. In order to continually meet this objective, organizational practices and procedures must be kept up to date with industry standards and align with a responsible utilization of TBHEDI resources. For the Asset Manager, this translates to the application of industry best practices for the optimization of; financial performance, operating performance, and business risk as they pertain to distribution system assets.

LIMITATIONS OF EXISTING/HISTORICAL TBHEDI ASSET MANAGEMENT SYSTEM

1) Presently, with the exception of substation power transformers, and to some degree, wood utility poles, TBHEDI has not developed an objective methodology which establishes the health (or remaining life) of a number of the significant asset classes (beyond referencing, for the most part, asset demographics). This is not to say that these components are neglected, but rather that the absence of an objective remaining life estimate process / tool makes the establishment of an appropriate maintenance regime and the effectiveness of such a program difficult to ascertain. Continued operation in the absence of an objective, standardized health metric may result in misdirected maintenance activities and inefficiencies with respect to capital replacement activities. In the near term however, the risk of capital replacements taking place out of sequence is acceptably low given that the 4kV to 25kV conversion strategy places considerable emphasis on the elimination of heavily aged, high impact infrastructure.

2) TBHEDI has performed informal, high level risk analysis with respect to the failure of certain priority assets on system reliability. While this level of analysis is sufficient to target long term capital replacement requirements, and a certain degree of escalated maintenance practices, it provides little in the way of gauging the impact that such activities, and their sub-programs, have on actual reliability indices.

3) TBHEDI's asset maintenance activities are exhaustive and well established practices. The execution of these activities are typically monitored and reported on by the appropriate supervisor. As maintenance demands caused by an increasingly ageing distribution network escalate, it is essential that the tracking, deployment, and prioritization of these activities

become further centralized in an effort to closely monitor their influence on asset health and related performance indices.

4) Data collection, management, and analysis has emerged to become the cornerstone to an effective asset management program. Historically, the TBHEDI Geographical Information System (GIS) was populated with static data related to an individual asset's characteristics (i.e. a pole's installation date or a transformer's primary voltage, etc.) and its geospatial location. The collection of additional asset data is now an ongoing initiative and is performed as required or as resource availability allows (i.e. pole framing configuration and transformer foundation material, etc.).

   As asset management strategies have grown in sophistication and their initiatives have become more specific, the demand for detailed asset characteristics has become greater and greater. For example, it is now no longer sufficient to know simply that a pole represented in GIS is wood and was installed in 1960; it must now also be known whether that pole holds crossarms fitted with wooden pins, restricted conductor and so on. Additionally, where it has been past practice for division supervisors to maintain independent databases of their respective maintenance activities, often only in hard copy format, these records must now be consolidated into a single database in order to efficiently facilitate planning of near term maintenance and long term capital replacements. This newly consolidated database must be routinely updated and editable by multiple stakeholders. Infrequent, mass data updates, while adequate for static asset characteristics, are insufficient given the frequency of maintenance activities and the degree to which their performance data may influence future maintenance and capital replacement decisions. In addition to maintenance tasks, findings, and scheduled activities, this database should also include asset specific contribution to system outages, consistently updated asset operation counter (i.e. for system switches and breakers), and should ideally be accessible through the TBHEDI GIS.

   Finally, in addition to increased data concentration and the demand for a consistently up-to-date data set; it is also essential that the integrity of this data be consistently maintained and audited as required. This necessity cannot be understated; its requirement is further compounded by the demands inherent to the recently deployed International Financial Reporting Standard (IFRS).

DEVELOPMENTS IN THE TBHEDI ASSET MANAGEMENT SYSTEM

A myriad of asset management tools, strategies, and organizational priorities exist today; each with its appropriate application. It is TBHEDI's opinion however that the greatest challenge is not in the selection of the appropriate tool or methodology but rather in the shifting of the cultural mindset from viewing the distribution network assets as a lump of homogeneous components with only the most problematic being subject to increased scrutiny and monitoring, to a philosophy of heterogeneity where each asset class and individual asset is independently managed in proportion to that asset's impact on the objectives of the corporation should it fail. This approach is critical to the management of what could otherwise be termed a province wide crisis of capital replacement backlog. It is in the hands of the local distribution company to manage this backlog such that the escalation of replacement rates is manageable while still providing a safe and robust supply. Practically speaking, this means that more will be demanded from ageing assets and as such, the development of an individualized health index and objective risk analysis is vital for the deferral of replacements where possible and the scheduling of such replacements where necessary.

Due to the substantial ageing of many in-service TBHEDI assets, it is accepted that the condition of these assets are reasonably correlated with their age. As these substantially aged assets are replaced, the determination of replacement priorities will become increasingly difficult.

In order to effectively prioritize future replacements and maintenance activities, TBHEDI intends to enhance its condition assessment practices by escalating application of condition assessment technologies, increasing resource allocation to these activities, and applying emerging health index determination principles[45] to the assessment results. It is expected that this proposed, more rigorous asset condition assessment regime will provide further validation for the expenditures proposed in Section 7 and assist in resource allocation as project prioritization becomes increasingly onerous.

In addition to an escalation in the asset condition assessment regime, TBHEDI also intends to increase the formality and objectivity with which risk assessment of distribution assets takes place.

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[45] TBHEDI staff were recently exposed to Kinetrics' asset management methodologies and intend to adopt a similar approach in future asset condition assessments.

This will involve the translation of known risk factors and consequences to a customized criticality matrix, again, for the purpose of maintenance and capital replacement prioritization.

Finally, TBHEDI is placing a high priority upon the centralization and effective presentation of its asset characteristics and operational data. Asset Management staff are actively leveraging and customizing the GIS database for this purpose while also auditing data flow processes in order to ensure its integrity and accuracy. To date, the TBHEDI GIS system has proven to be a remarkable tool with respect to reporting on asset characteristics, demographics, and the like. TBHEDI's near term objective is to continue the growth of the GIS database into a dynamic environment which can be reliably leveraged by all departments with confidence.

APPENDIX 2-B
Green Energy Act Plan

Appendix B

Thunder Bay Hydro Electricity Distribution Inc.

Basic Green Energy Act Plan

2012-11-08

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Executive Summary

Thunder Bay Hydro Electricity Distribution Inc. (Thunder Bay Hydro) is a local electricity distributor serving approximately 50,000 customers in Thunder Bay, Ontario. In accordance with the Ontario Energy Board's Filing Requirements, EB-2009-0397[2], Thunder Bay Hydro has prepared a Basic Green Energy Act (GEA) Plan. The GEA Plan is based on current information and presents Thunder Bay Hydro's near-term and long-term plans that are intended to accommodate the connection of renewable generation facilities.

Current Assessment

Initial interest in renewable generation development in the Thunder Bay Hydro service territory was high but has stalled in response to the OPA's review of the FIT program and capacity limitations associated with regional and transformer station constraints.

As at June 2012, Thunder Bay Hydro has a connected capacity of;

- 1,093kW of microFIT projects;
- 175kW of Capacity Allocation Exempt projects; and

[2] EB-2009-0397 excerpt;
"*The materiality threshold* (for filing a Detailed GEA Plan) *is reached, for the purposes of these Filing Requirements, in either of the two following circumstances:*

1. *The total capital costs of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid in any one year:*
   - *Are more than $100,000 and exceed 3% of the distributor's distribution rate base; or*
   - *Exceed $5,000,000*
2. *The total capital cost of all a distributor's planned projects related to the connection of renewable generation and/or the development of a smart grid over five years:*
   - *Are more than $100,000 and exceed 6% of the distribution rate base; or*
   - *Exceed $10,000,000*

<u>In all other circumstances</u>, a distributor must file a Basic GEA Plan with its cost of service rate application…"

- 19.7MW of Non-Capacity Allocation Exempt projects.

Renewable Generation Integration Strategy

Transitioning the Thunder Bay Hydro network to function bi-directionally, with multiple embedded sources presents numerous significant challenges. Through analysis it has been determined that the most immediate area of concern is operational and related to the limitations of existing protections and SCADA[3] infrastructure. Thunder Bay Hydro has initiated deployment of remotely located self contained reclosers, associated intelligent electronic control devices, and dedicated communication equipment which will address existing limitations.

The anticipated cost schedule for the deployment of the self contained reclosers (and associated components) is as follows;

Year	Feeder	Recloser Assemblies Required	Estimated Cost of Deployment
2012	10M8	6	$384,154
2013	10M5	3	$193,577
2013	10M6	6	$384,154
		Total	$967,885

[3] SCADA – Supervisory Control and Data Acquisition

Current Assessment of the Thunder Bay Hydro System

The City of Thunder Bay is serviced from three, Hydro One owned transformer stations (TS); Birch TS, Fort William TS, and Port Arthur TS. These transformer stations supply Thunder Bay Hydro with a distribution level voltage of 25kV.

The majority of Thunder Bay Hydro customers receive primary service at the 25kV voltage level directly from one of the three Hydro One owned transformer stations (58% of all customers). The city's older urban districts (34% of all customers) are serviced at 4kV from fourteen Thunder Bay Hydro owned distribution stations (DS). Finally, the remaining 8%, primarily rural customers, are serviced at 12kV from four distribution stations also owned and managed by Thunder Bay Hydro. The following table lists the ownership, voltage level and designation of each TS and DS which is directly connected to the Thunder Bay Hydro network:

Designation		Voltage Level	Ownership
P02	Port Arthur TS	25kV	Hydro One
P17	Birch TS	25kV	Hydro One
P10	Fort William TS	25kV	Hydro One
3	Hardisty	4kV	Thunder Bay Hydro
4	Vickers	4kV	Thunder Bay Hydro
5	Donald	4kV	Thunder Bay Hydro
6	McPherson	4kV	Thunder Bay Hydro
7	Mary	4kV	Thunder Bay Hydro
9	Mountdale	4kV	Thunder Bay Hydro
11	High	4kV	Thunder Bay Hydro
12	Camelot	4kV	Thunder Bay Hydro

Designation		Voltage Level	Ownership
14	Algoma	4kV	Thunder Bay Hydro
15	Grenville	4kV	Thunder Bay Hydro
16	MacDonnell	4kV	Thunder Bay Hydro
18	Balsam	4kV & 12kV	Thunder Bay Hydro
19	Broadway	12kV	Thunder Bay Hydro
21	Windemere	4kV	Thunder Bay Hydro
22	Brock	4kV	Thunder Bay Hydro
23	Alice	12kV	Thunder Bay Hydro
36	Mapleward	12kV	Thunder Bay Hydro

Table 1 - Thunder Bay Hydro System Transformer/Distribution Stations

Thunder Bay Hydro employs a twofold approach when determining the gross capacity of the distribution system to accept renewable generation connections. Determination of capacity in the following manner does not account for restrictions related to imposing bi-directionality on a system originally designed for unidirectional power flow. Rather, the following provides a hard ceiling for renewable generation connections imposed by the current carrying limitations of the Thunder Bay Hydro owned distribution assets.

1. Where the proposed connection point is downstream of a Thunder Bay Hydro owned DS, the gross capacity is determined to be equivalent to 2/3 of the aggregate rating of power transformer(s) located within the upstream DS. The net capacity is this amount less the aggregation of generation already connected to any and all feeders being supplied by the DS.

2. Where the proposed connection point is directly to the 25kV network, the gross capacity is determined to be equivalent to 400A per feeder (17.3MVA) plus 2/3 of the minimum feeder load. In this way, Thunder Bay Hydro does not account for capacity restrictions imposed by the transmitter owned transformer stations but rather allows Hydro One to enforce the restrictions on its own assets.

Hydro One determines the renewable generation capacity of the Port Arthur, Birch, and Fort William transformer stations separately from the Thunder Bay Hydro process. The available capacity for each station is publicly available at www.hydroone.com and is listed on the "Hydro One List of Station Capacity" (last updated February 23, 2012). Transformer station capacities are given as "Short Circuit Capacity" and "Thermal Capacity" and applied as a capacity pool to the entire station. The net station capacity is the gross capacity less the aggregation of the existing downstream generator's short circuit and thermal contributions. Presently, capacity for the connection of renewable generation facilities to the Thunder Bay Hydro network is limited by the Hydro One TS capacities (as opposed to being limited by the Thunder Bay Hydro owned assets).

Finally, the City of Thunder Bay falls within the 'Northwest' region of the provincial transmission system (as defined by the Ontario Power Authority[4]). Pending upgrades to the transmission system, it has been determined[5] that the global capacity for renewable generation development in this region is restricted to a total of 100MW. This limitation is due to weak loading in the region, resulting in an excess of power production.

[4] Per the 'Ontario Transmission System Map Tool' found on the OPA FIT website.
[5] Per the 'Transmission Station Availability Table' found on the OPA FIT website. Last updated October 2, 2009.

Present Levels of Renewable Generation Development

The City of Thunder Bay represents an attractive opportunity to renewable energy developers. The geography provides a strong solar and wind resource, a slow growing economy results in cost effective real estate and an eager work force and finally, an environment of cooperation fostered by Thunder Bay Hydro has led to a high success rate for individual project developers.

Thunder Bay's favourable renewable generation resource has been known for some time however it was the Ontario Power Authority's (OPA) 'Renewable Energy Standard Offer Program' (RESOP) which caused Thunder Bay Hydro to bring the management of these connections to the forefront of its operational objectives. Following the original onslaught of applications, and conceivably due to the onerous nature of the process, efforts of large scale renewable generation developers in the Thunder Bay Hydro service territory waned and only slightly rebounded with the advent of the Feed-in-Tariff (FIT) program.

As at June 2012, there have been four renewable generation connections greater than 500kW made in the Thunder Bay Hydro service territory. All of these projects are participants of the OPA's RESOP program. Thunder Bay Hydro has seen several 'Capacity Allocation Required' (CAR) applications under the FIT program, one of which has the necessary LDC/Transmitter approvals required to proceed while the remainder of the applications continue to populate the OPA's application queue (presumably waiting to undergo the 'Economic Connection Test' (ECT)).

Thunder Bay Hydro has also received a number of applications for connection of 'Capacity Allocation Exempt'[6] (CAE) FIT projects. To date three of these projects have

[6] "capacity allocation exempt small embedded generation facility" means an embedded generation facility which is not a micro-embedded generation facility and which has a name-plate rated capacity of 250 kW or less in the case of a facility connected to a less than 15 kV line and 500 kW or less in the case of a facility connected to a 15 kV or greater line – Distribution System Code, October 1, 2011

been connected however capacity continues to be reserved for the remaining projects until THUNDER BAY HYDRO receives direction to the contrary from the OPA or the customer chooses to rescind their application.

THUNDER BAY HYDRO has seen by far the greatest renewable generation uptake take place under the microFIT program. As at June 2012, THUNDER BAY HYDRO has successfully connected 122 microFIT projects and continues to receive connection requests at a steady pace. Much of this program's local success can be attributed to the early development of THUNDER BAY HYDRO's microFIT management program in conjunction with the aggressive development strategies employed by a number of local solar photovoltaic development groups.

MicroFIT

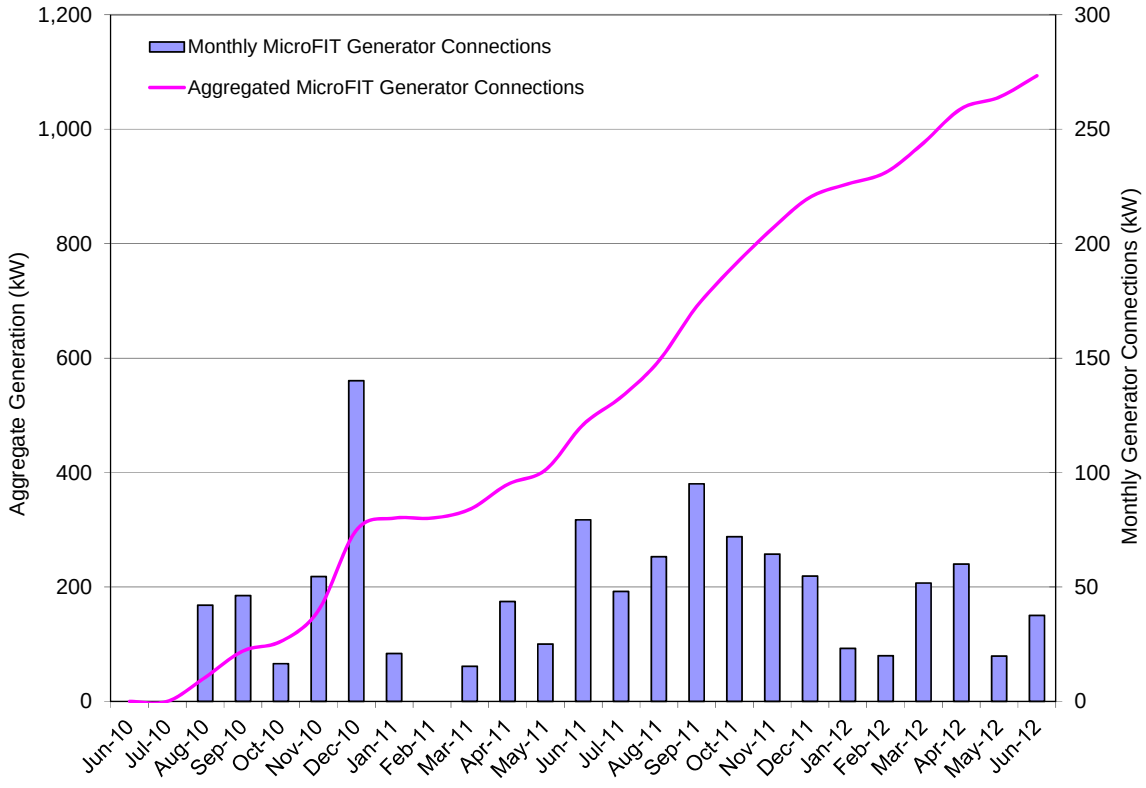

Figure 1 - Progressive microFIT Generation Development

Beginning in August of 2010, Thunder Bay Hydro has connected an average of 47kW of microFIT generation projects per month (or 5.3 projects per month). As at June 2012, a total of 122 microFIT projects have been connected to the Thunder Bay Hydro distribution system at all voltage levels (25, 12, and 4kV) and to 49 unique feeders. The sum total nameplate value of all microFIT generation projects connected to the Thunder Bay Hydro network is 1,093kW.

The historical trend of generation connections over time (Figure 1) indicates a strong linear growth in microFIT connections. The future trend of microFIT development is difficult to predict given that future microFIT connections will be subject to the reduced compensation rate released in the microFIT 2.0 rules. For the purposes of this report Thunder Bay Hydro assumes that, although rates have been reduced, microFIT development will continue to represent an attractive investment and, in fact, escalate in response to the marketing strategies of local developers.

Capacity Allocation Exempt

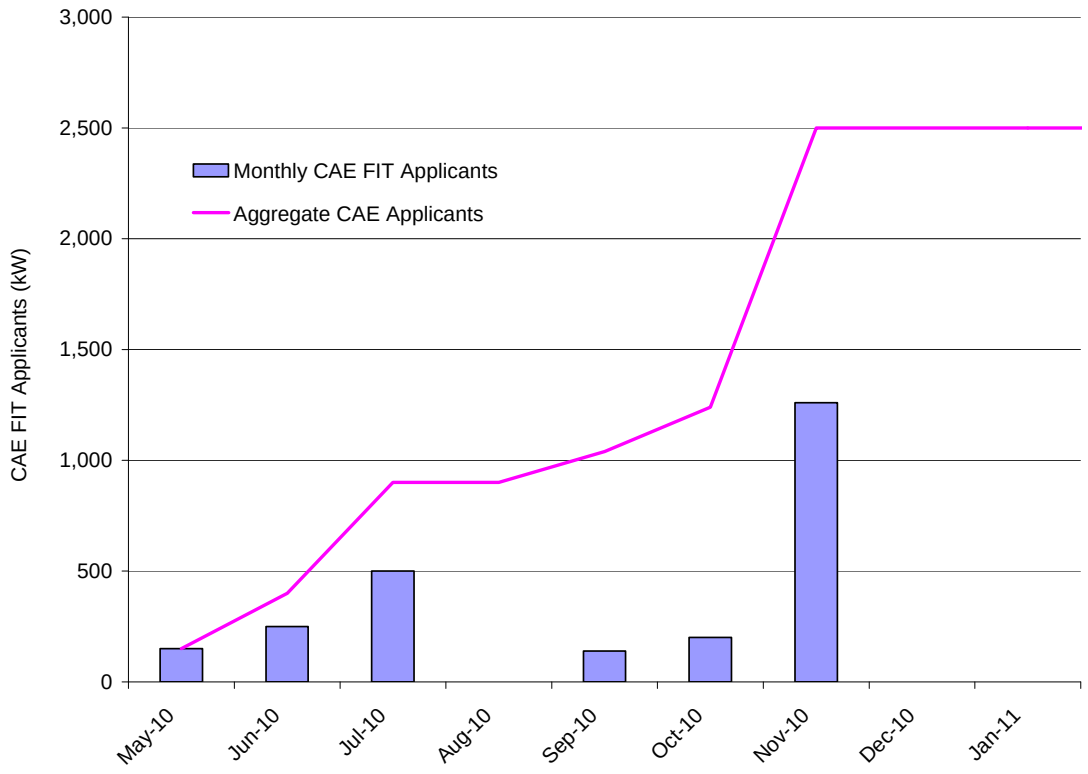

Figure 2 - Progressive CAE Generation Development

As at June 2012, there exist 18 applicants for the connection of CAE generation projects to the Thunder Bay Hydro distribution network. Three of these applicants have successfully connected (a total of 175kW) while the remaining 15 continue to progress through the connection process.

As seen in Figure 2, Thunder Bay Hydro saw reasonable CAE development in the early days of the FIT program (additional applications were received above the existing 18 however these applications were later rescinded) but uptake has waned. Presently, the pool of CAE applicants combines for a total of 2.5MW and is distributed to 13 feeders (25 and 4kV).

Non-Capacity Allocation Exempt

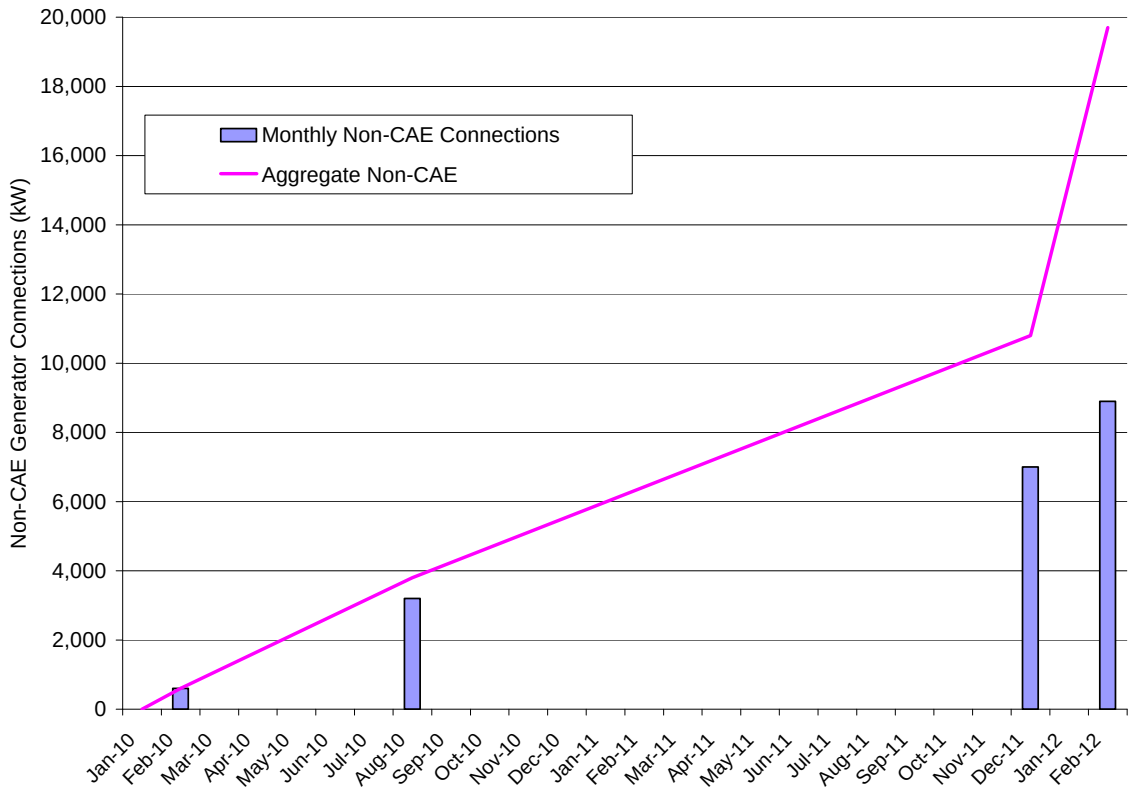

Figure 3 - Progressive Non-CAE Generation Development

As discussed previously, Thunder Bay Hydro has yet to connect a Non-CAE generator under the FIT program. To date, there have been 4 successful connections of Non-CAE scale projects under the legacy RESOP program. These projects are listed in Table 2.

Project	Description	Capacity	Feeder	Connection Date
WWTP	Anaerobic Bio-digester at the Thunder Bay Wastewater Treatment Plant	600kW	10M3	Feb, 2010
MRGS	"Mapleward Renewable Generating Station": Landfill Gas Utilization at the Thunder Bay Landfill	3,200kW	36F2	Aug, 2010
TBS1	Solar farm located at the Thunder Bay Airport	7,000kW	10M8	Dec, 2011
TBS2	Solar farm located on the property of the Fort William First Nations	8,900kW	10M5	Feb, 2012

Table 2 – In-Service Non-CAE Projects

The chronological connection of these projects and resulting total Non-CAE capacity connected to the Thunder Bay Hydro network is shown in Figure 3.

Table 3, taken from the OPA's 'FIT Application Management Environment' (FAME), provides the list of Non-CAE FIT applicants presently queued for connection to the Thunder Bay Hydro network. Thunder Bay Hydro has performed 'Distribution Availability Tests' (DAT) for the first three projects listed. Based on this high level analysis it was determined that, due to the capacity restrictions placed by existing generation projects TBS1 and TBS2, only the first project would be eligible for connection to the feeder as proposed. This resulted in a 'PASS' to the first applicant and 'FAILs' to the 10M5 and 10M8 applicants. Thunder Bay Hydro proceeded to conduct a Connection Impact Assessment (CIA) for the project which passed the DAT. Since the final CIA revision was conducted (February 2, 2011) the applicant has expressed their intention to proceed with construction targeting an in-service date of mid to late 2013.

The remaining five applications have not moved beyond the 'Transmission Availability Test' (TAT) stage, presumably awaiting the ECT. As such, Thunder Bay Hydro has not yet performed the DAT for these projects.

FIT Reference	Capacity (kW)	Feeder	Application Status	Thunder Bay Hydro CIA Completed
FIT-F1T6SPV	16,500	10M6	PASS	Yes
FIT-F9479NF	16,500	10M5	FAIL	No
FIT-FNTNJDG	15,000	10M8	FAIL	No
FIT-FI6F9HD	16,000	10M9	TAT	No
FIT-FGPDTH4	15,000	10M10	TAT	No
FIT-FN94YTM	7,700	10M8	TAT	No
FIT-F9HDZ1F	10,000	10M5	TAT	No
FIT-FKRB7X0	2,100	10M6	TAT	No

Table 3 - FAME Non-CAE Queue for Thunder Bay Hydro Territory

Present Capacity for the Connection of Renewable Generation

Tables 4 & 5 provide the current capacity for the Thunder Bay Hydro distribution system to accommodate renewable generation facilities on;

- those feeders directly connected to a transformer station (the 25kV network) and;
- those feeders for which the OPA has received one or more applications from renewable generators under the FIT program (RESOP facilities are also included).

Transformer Station (Hydro One Owned)	Feeder	Allocated Generation Capacity (kW)	Net Feeder Capacity (kVA)	Net Station Capacity for Renewable Generator Connections (Per Hydro One)	
				Short Circuit Capacity (kVA)	Thermal Capacity (kW)
Port Arthur TS	02M1	0	17,020	24,400	31,000
	02M2	100	10,645		
	02M3	0	18,634		
	02M4	0	15,413		
	02M5	0	11,353		
Fort William TS	10M1	410	15,348	214,600	69,700
	10M2	0	16,842		
	10M3	600	13,623		
	10M4	200	10,242		
	10M5	8,900	10,899		
	10M6	16,000	2,286		
	10M7	100	14,143		
	10M8	7,115	9,237		
	10M9	150	17,679		
	10M10	0	16,645		
Birch TS	17M1	0	19,228	132,100	65,100
	17M2	150	15,353		
	17M3	0	20,760		
	17M4	100	15,948		
	17M5	225	19,724		
	17M6	150	19,114		
	17M7	250	14,844		
	17M8	0	16,308		

Table 4 - Thunder Bay Hydro Capacity to Accommodate Renewable Generation

(TS Connected Feeders)

Distribution Station (Thunder Bay Hydro Owned)	Feeder	Allocated Generation Capacity (kW)	Net Station Capacity (kVA)
#7 – Mary St.	7F4	50	2,900
#36 - Mapleward	36F2	3,200	600

Table 5 - Thunder Bay Hydro Capacity to Accommodate Renewable Generation (DS Connected Feeders with Allocated Capacity)

Factors Limiting Full Utilization of Available Capacity

Currently, Thunder Bay Hydro has a net available capacity for renewable generation of approximately 400MW. The limitations of the three Hydro One owned transformer stations (based on the 60% reverse flow tolerance of the transformers) curtail this capacity to 166.4MW[7]. Finally, the regional capacity constraint of 100MW further limits the 166MW available at the transformer stations to 100MW less the capacity already granted to generators connected to transformer stations within the same region but in another distributor's territory.

Thunder Bay Hydro's Renewable Generation Integration Strategy

The connection of large renewable generation facilities to the distribution system poses many interesting challenges. In most cases, these challenges can be addressed by distribution system upgrades that the Ontario Energy Board has defined in the Distribution System Code as "Renewable Enabling Improvements"[8]. Renewable Enabling Improvements, as described in the Code, are limited to the following;

- modifications to, or the addition of, electrical protection equipment;

[7] Thermal capacity only, unique short circuit contribution of a generator may limit this capacity further.
[8] Distribution System Code, Section 3.3.2

- modifications to, or the addition of, voltage regulating transformer controls or station controls;
- the provision of protection against islanding (transfer trip or equivalent);
- bidirectional reclosers;
- tap-changer controls or relays;
- replacing breaker protection relays;
- Supervisory Control and Data Acquisition system design, construction and connection;
- any other modifications or additions to allow for and accommodate 2-way electrical flows or reverse flows; and
- communication systems to facilitate the connection of renewable energy generation facilities.

The Thunder Bay Hydro renewable generation integration strategy is to apply the appropriate renewable enabling improvements which will most economically allow the Thunder Bay Hydro system to migrate to a safe, manageable, and reliable bi-directional network.

The following provides a detailed review of the present state of the Thunder Bay Hydro system components and the upgrades required to accommodate large renewable generation facilities. Presently, Thunder Bay Hydro has limited the scope of its renewable enabling improvements to include SCADA and system protections.

Current State of Thunder Bay Hydro Protections

At present, Thunder Bay Hydro's distribution network consists of a multi-voltage substation design with operational voltage levels of 25, 12, and 4 kV. In an effort to reduce system losses, provide customers with higher system reliability, and reduce maintenance costs, Thunder Bay Hydro is aggressively eliminating the 4kV portion of

the network and transferring its load to the 25kV platform. Complete elimination of the 4kV network is expected to take place by 2023.

The protection scheme currently utilized on the 25kV network is a “fuse saving” reclosing scheme which is controlled by electromechanical relays (Westinghouse, CO-11 – deployed by Hydro One in 1976). The intended operation of these devices is to detect faults with as much sensitivity and selectivity possible while still being able to sustain periods of high current demand such as cold load pick-up, transformer inrush, etc.

In a fuse saving scheme, a fault which has been detected by the relay, but is downstream of a lateral fuse, will result in the relay temporarily opening the feeder breaker (typically for a period of 3 seconds), followed by a reclose of that breaker. If the fault is permanent, the properly coordinated scheme would result in the lateral fuse blowing thereby extinguishing the fault and isolating the failed section from the network. If the system is mis-coordinated, or if the fault is present on a portion of the system not protected by fusing, a permanent fault will result in a lock out (or permanent opening) of the feeder breaker.

The 12kV & 4kV portions of the distribution system operate with similar functionality to the scheme described above (12kV operates in a fuse saving capacity while the 4kV operates in a fuse blowing capacity). Since each 4/12kV substation is fed by the 25kV network, the 4/12kV protective devices have the effect of truncating the feeder length necessary to be protected from the 25kV head node. In doing so, a properly coordinated 4/12kV substation would effectively cushion customers of the 25kV network from faults sustained downstream of the substation, theoretically increasing the reliability of the 25kV backbone.

As the Thunder Bay Hydro distribution network is converted to 25kV the existing Hydro One owned feeder protection relays are required to extend their “reach” to much more remote sections of the network. The introduction of large scale

renewable generation facilities will push existing protections beyond their abilities to perform their function within acceptable limits.

Protection Challenges Presented by Embedded Generation & Solutions in Development

Bi-Directionality of Current Flow

Traditional electrical distribution systems are designed for a single direction of power flow – from the transmission station to the customer.

When a renewable generator is connected at the distribution level current flow becomes unpredictable. The instantaneous direction of current travel in this type of system is dynamic and is dependant on numerous variables such as generation output, customer demand and system configuration. Bi-directional current flow is incredibly difficult (if not impossible) for the human operator to manage and its presence, if not understood by existing protective relays, can have a significant impact on system reliability statistics.

Bi-Directionality and the Human Operator

In the conventional system with no generation, the operator can be assured that the customer demand on a feeder is equivalent to the demand being measured at the feeder head node. Should a feeder breaker be disengaged for any reason, the operator can confidently reassign the load to an adjacent feeder which is capable of managing the additional demand.

In the bi-directional system, the operator is unable to determine the penetration of the renewable generation into the distribution system. As such, the measurement of current at the head node is meaningless without considering how much of the demand is being offset by the embedded sources.

In order to accurately re-configure the system, the operator must have visibility into all points within the system which could provide an alternate path for current flow and hence hide customer loads from the view of system control operators.

Further, due to the intermittent nature of certain renewable fuels, the operator cannot assume that the level of generation will remain constant from one moment to the next and must be provided with a steady stream of network wide updates to facilitate any switching operations.

As a minimum, Thunder Bay Hydro must expand its visibility into the distribution network. System characteristics (ie. voltage, current (magnitude and direction)) must be monitored at strategic locations, in particular those junctions where power flow may reverse, at the immediate point of common coupling between the generator and the utility, or where a parallel point may be utilized to pick up loading from adjacent feeders.

The selected monitoring system must be capable of remote operation and interrogation. The monitoring system must also be compatible with Thunder Bay Hydro`s existing SCADA infrastructure. The most practical and economical means of communication for this type of system is by way of radio.

Failure to implement a monitoring system as proposed will severely impact the operator's decision making ability and reduce overall system reliability and power quality.

Bi-Directionality and Conventional Protective Relays

In the conventional network, a fault is only detected and cleared by the protections that are present on that specific feeder. It is rare that an adjacent feeder fault would impact the continuity of service on any other unfaulted feeder.

In the bi-directional system, fault current may now be sourced not only from the transmission system but now also from renewable generation sources on adjacent

feeders. Under these conditions, when a faulted feeder shares a substation bus with a feeder carrying renewable generation the adjacent renewable generator becomes a fault current source. Since the Hydro One owned CO-11 relay does not comprehend current directionality, the unfaulted feeder breaker may trip needlessly ("nuisance trip") rather than riding through the fault and allowing for proper coordination.

Hydro One has acknowledged the limitation of the existing CO-11 protective relays and is replacing these units with modern GE-D60 relays. These solid-state relays offer numerous enhancements over their predecessors including bi-directional sensing, networking and transfer tripping (discussed in Section 0).

One advantage of these modern devices is their ability to restrain operation in the event that reverse current is sensed during a fault, eliminating the opportunity for nuisance trips during adjacent feeder faults.

Protective Device Reach

The reach of a protective device is the distance along a conductor which a protective relay is able to accurately distinguish fault current from load current. As a fault moves further from a protective device or as impedance is introduced within a fault, the magnitude of the fault current seen by the protective relay is reduced; effectively limiting the reach of the device. Currently, Thunder Bay Hydro designs its protective relay settings to detect and clear a fault, with given impedance, at any point inside the relay's zone of protection under all contingencies within a desired time period.

It is a characteristic of the high impedance fault to only demand a finite amount of current. The addition of renewable generation to the distribution system provides additional sources for fault current and hence a portion of the fault current demanded by these faults. Since the conventional feeder protections have been tuned to detect a certain level of current as an indicator of high impedance faults, an

alternate current source has the effect of limiting the current detected by the head node device to below the operational threshold. Therefore, the addition of the renewable generation will limit the reach of the conventional relay by an amount proportional to the generator's capacity to feed a fault and the physical location of the generator on the circuit. This limitation extends to contingent conditions which would have been sufficiently protected in the past but would now violate the Thunder Bay Hydro protection criteria.

In order to overcome the effect of reduced protective relay reach, the zone of protection must be truncated to a point at which the Thunder Bay Hydro protection criterion is restored. This can be achieved by the strategic placement of self contained reclosers throughout the network.

The recloser offers the same functionality as the feeder breaker but reduces the zone of protection to the length of conductor between the feeder breaker and the recloser rather than the entire feeder. For proper coordination, recloser locations are determined through simulation and, in order not to limit contingent options for the system operator; reclosers may also be required at strategic normally open points throughout the system.

The specified recloser units must accommodate bi-directional power flow and be capable of intelligently altering protection settings depending on current direction. The specified reclosing units must also operate in a "ganged" fashion to avoid single phasing of loads/generators and back-feeding through delta connected transformers.

Renewable Generator Steady State Capacity

Thunder Bay Hydro's traditional means of providing protection to any lateral circuit is to install a fuse of sufficient capacity to carry the anticipated load current while providing protection to the downstream cables and devices. Once a fuse size exceeds a certain threshold its Time Current Characteristic (TCC) curve encroaches

on the upstream protective relays and results in nuisance tripping of upstream customers.

Thunder Bay Hydro's protective relays are limited to coordination with fuse sizes 200E or less. As such, any renewable generation connection capable of greater than 200A sustained current must be protected at its point of common coupling by some means other than a standard fuse since the regular steady state current produced by the generator will be sufficient to blow the fuse.

In order to avoid nuisance tripping while still providing the necessary protection to downstream equipment, the protective device located at the generation/utility point of common coupling must be capable of;

- a sustained current equal to or greater than the steady state capacity of the generator;
- an operational profile which properly coordinates with upstream protective devices;
- comprehension and adaptability to bi-directional power flow scenarios.

Potential for Islanding

When a large renewable generator is connected to a distribution system a theoretically possible scenario exists called "islanding". Islanding refers to a period in which a feeder is disengaged from the distribution system yet remains energized through its connection to the renewable generation facility. An islanded feeder presents the following unwanted scenarios;

- worker safety is compromised when feeders remain energized during an intended outage;
- customers serviced from an island may experience poor power quality;

- islanded generation may become unsynchronized from the main supply. Reclosing without synchronization can result in catastrophic failure of system components.

The conventional means of guaranteeing protection from islanding is to implement a "transfer trip" scheme. In a transfer trip scheme, the generator breaker is coupled (by means of a long distance communication channel) to the main feeder breaker. When the main feeder breaker opens, a signal is sent to the generator which causes the generator breaker to operate, taking the generation facility offline. Once offline, the generator responds to the main feeder breaker with its status. Once the main feeder breaker is re-engaged, the generator breaker is authorized to re-connect to the system.

Hydro One has implemented the GE D60 relay at the head node of every feeder supplying Thunder Bay Hydro which will have large renewable generation connected downstream. This device is capable of initiating a transfer trip signal in the event of a fault. A separate transfer trip channel is required for every feeder which will at some point feed the downstream generator. Due to the cost prohibitive nature of having multiple transfer trip connections for a single generator it is standard practice for a large generator to have a single dedicated feeder to which they must be coupled. As a result, a large renewable generator may only generate under normal system conditions where fed by its dedicated system breaker. If the feeder to which the generator is connected is fed by an alternate breaker under some contingency, the generator must be brought offline and remain offline until normal conditions are restored.

In the case where a generator connects downstream of a Thunder Bay Hydro owned DS (ie. anywhere within the 4kV or 12kV networks), Thunder Bay Hydro must also provide a transfer trip link to the generation facility. This link is required since the Hydro One zone of protection does not extend beyond the Thunder Bay Hydro

owned substation transformers and is therefore unable to protect against islanding of the stepped-down sub-network. A practical example of this scenario is the connection of the Mapleward Renewable Generating Station (MRGS) on the 12kV feeder 36F2. It was determined at the time of Connection Impact Assessment that the MRGS facility was of sufficient capacity to sustain an island in the event that primary protections failed and the feeder load matched closely the generator's output. As such, a transfer trip element was required at the head node of 36F2 in the Mapleward DS in addition to the standard transfer trip deployment at the Hydro One owned 25kV breaker which feeds the Mapleward DS. The existing recloser units which were protecting feeder 36F2 were of a class and vintage which had no economical means of being retrofitted to accommodate the transfer trip requirement. These legacy devices were replaced at the expense of the generator prior to the connection of MRGS. The new devices (G&W Viper reclosers fitted with SEL-651R recloser controllers) not only addressed the immediate, mandatory requirement for anti-islanding protection but are also capable of accommodating bi-directional power flow, and provide enhanced network visibility for the Thunder Bay Hydro system operators.

Since the existing transfer trip solution is an inefficient, one-to-one relationship. Thunder Bay Hydro has proposed to Hydro One that transfer tripping become a multiplexed solution which would involve a many-to-many relationship, thereby allowing generators to access multiple contingencies. This solution is on hold pending further investigation.

Reliability and Continuity of Service

Thunder Bay Hydro is able to ensure its customers high levels of reliability by leveraging the support of contingent feeders. Should a fault occur on a remote section of a feeder unprotected by fuses, it is common practice to patrol the feeder and manually sectionalize the fault prior to restoration of service. This practice

remains acceptable for load customers who are indifferent to which distribution feeder to which they are connected. Further, in the conventional system, redistribution of load to adjacent feeders remains a relatively simple task for the human operator to manage.

Unlike load customers, the renewable generator's income is based completely on its ability to continuously export power to the distribution system. As such, the renewable generator will demand continuity of service which is equivalent to (if not greater than) the service provided to the conventional customer. Unfortunately, due to the one-to-one relationship of the presently implemented transfer trip scheme, the generator cannot be guaranteed the same reliability as its neighbouring load customer. It is Thunder Bay Hydro's responsibility to ensure that the feeder to which the generator is dedicated sustains the minimum frequency and duration of outages possible. In order to achieve this, the speed with which a fault is isolated and the renewable generator restored to its primary feed is paramount. This challenge involves addressing three major factors;

1. Expediting the detection and isolation of faulted sections,
2. Expediting the human operator's ability to reliably transfer load/generation,
3. Eliminating the one-to-one transfer trip relationship.

In order to expedite the detection and isolation of faulted sections within the network, additional devices must be added which will act to sectionalize the feeder into a number of smaller sections. Segmenting the feeder in such a fashion will result in the minimum number of customers being affected in the event of a fault. The selected devices must be capable of bi-directional power flow, fault current interruption, provision of a visible open point, hot-line tagging, etc.

As discussed in section 0, the characteristics of a bi-directional distribution system make the human operator's job incredibly complex. This is further complicated under unplanned, faulted conditions. While the additional devices proposed above provide the operator with a number of options for sectionalization and re-distribution of load, the speed with which the devices are operated is still limited to human decision and manual operation. In order to take full advantage of the enhanced switchability it is proposed that the selected devices be capable of semi-autonomous operation. Devices which operate in semi (or fully) autonomous mode will require a dedicated communication network to allow sharing of real-time information between devices and the facilitation of rapid fault isolation and load re-distribution. These devices will leverage enhanced computing and pre-programmed scenarios to minimize outage durations and actively re-assign load/generation in the bi-directional network.

Presently, Hydro One manages the implementation of all transfer tripping from the Hydro One owned transformer stations. As discussed, the one-to-one relationship of the existing transfer trip scheme severely limits the ability of Thunder Bay Hydro to provide highly reliable service to its renewable generation customers. The proposed devices should be capable of managing the existing transfer trip scheme while also allowing for a future, multiplexed design. This future design would eliminate the one-to-one transfer trip relationship and afford the generator continuity of service equivalent to the conventional load customer.

In-Progress System Developments

In September of 2011, Thunder Bay Hydro released a request for proposals (RFP #11-48) designed to address the challenges listed in section 0 for the two feeders with the highest levels of renewable generation penetration (10M8 & 10M5). The RFP was awarded in December of 2011.

The resulting design concept, as anticipated, involves the installation of strategically placed, self contained reclosers throughout the affected feeders. The recloser devices are equipped with the necessary telemetry and intelligence which will allow them to carry out operations to the extent described in section 0.

Thunder Bay Hydro has six of these self contained units on order in addition to a single real time automation controller and specialized high speed communication equipment designed to manage the entire protection scheme. These six units will be strategically located on feeder 10M8 in response to the connection of the 7MW solar project, TBS1.

The estimated cost in 2012 for the materials and labour associated with the recloser deployment is $387,154.

5 Year Renewable Generation Forecast

At present it is difficult to predict the levels of continued renewable generation development under the FIT program. Historical trends are expected to shift in response to the OPA's recently announced reduced FIT rates and, the removal of the CAE exemption from the transmission availability test.

The following assumptions have been made in order to develop a plausible 5-year Renewable Generation Forecast;

1. **The revised FIT/microFIT rates have retained the originally intended rate of return for eligible projects.**

   After consultation with local development groups, Thunder Bay Hydro anticipates escalated microFIT growth due to renewed aggression in the marketplace and revised business plans which increase customer accessibility to the program.

   MicroFIT growth is projected as follows;

Year	Number of Projects	Average Size of Project (kW)	Annual Aggregate (kW)
2012	60	9	540
2013	80	9	720
2014	100	9	900
2015	120	9	1,080
2016	140	9	1,260

Table 6 - Projected microFIT Development Growth

2. **The regional constraints will remain for the period in question.**

   In this scenario, the 16MW project already allocated to feeder 10M6 is expected to connect however, further development of projects with a nameplate in excess of 10kW is expected to be limited.

Generator Class	2012	2013	2014	2015	2016
microFIT	540	720	900	1,080	1,260
CAE	1,000*	125	125	125	125
Non-CAE	8,900**	16,000	0	0	0
Total	10,440	16,845	1,125	1,205	1,385
*Anticipated connection of queued CAE projects **Project is already connected (TBS2: February, 2012)					

Table 7 – 5 Year Renewable Generation Forecast

(Generation quantities given in kW)

5 Year Distribution System Development Forecast

Thunder Bay Hydro plans to implement the discussed self contained recloser solution on all feeders which are subject to high levels of renewable generation penetration. This includes:

- 2012 deployment of 6 recloser systems on feeder 10M8 in response to the 7MW solar farm, TBS1, which was connected in December of 2011;
- 2013 deployment of 3 recloser systems on feeder 10M5 in response to 8.9MW solar farm, TBS2, which was connected in February of 2012, and,
- 2013 deployment of 6 recloser systems on feeder 10M6 in response to the anticipated connection of the 16MW Horizon wind farm.

In lieu of future approvals of high penetration renewable generation, this distribution system development forecast (Table 8) is limited to the next two years.

Year	Feeder	Recloser Assemblies Required	Estimated Cost
2012	10M8	6	$387,154
2013	10M5	3	$193,577
2013	10M6	6	$387,154
		Total	$967,885

Table 8 - Distribution System Development Forecast

System Development Cost Recovery Strategy

On October 21, 2009, through an amendment to the Distribution System Code[9], the Ontario Energy Board revised the cost responsibility rules as they pertain to distribution connected renewable generation facilities. Among other cost responsibility mechanisms, this amendment introduced the concept of Renewable Enabling Improvements. The preamble to the Board's amendment makes it clear that these revised cost responsibility terms only apply to those renewable generation projects which have applied for connection on or after October 21, 2009.

As discussed in Section 0 and 0, Thunder Bay Hydro is making system investments in response to the two, high penetration RESOP projects presently connected to feeders 10M8 and 10M5. These projects originally applied for connection in November of 2006, well in advance of the amended cost responsibility rules. At the time of application, Thunder Bay Hydro prepared a Connection Impact Assessment which applied the best practices of the day. The outcome of the Connection Impact Assessment became the driver for costs associated with the physical connections of the two projects as well as the transfer trip scheme as mandated by Hydro One. These costs were billed directly to and recovered from the applicant. Despite the fulfillment of the distributor's immediate obligations to the generator, Thunder Bay

[9] EB-2009-0077

Hydro was aware that additional investment may become necessary as industry experience with distributor embedded generation connections grew.

In the period from 2007-2010 the industry observed several iterations of the RESOP program and the Distribution System Code, the Royal Assent of the Green Energy Act, and the inception of the FIT Program. Private and public sector responded to the new legislation and programs by introducing an array of enhanced distribution system technologies and implementation test beds. Throughout this period Thunder Bay Hydro acknowledged the importance of managing the challenges listed in Section 0 however it wasn't until recently (2010 to present) that Thunder Bay Hydro was sufficiently convinced of the market's maturity and the stability of the technologies to allow for prudent investment. Thunder Bay Hydro is confident that, had these system investments been undertaken in response to generation facilities which had applied for connection post to October 21, 2009, these investments would qualify as Renewable Enabling Improvements. However, due to the timing of these renewable generation applications, Thunder Bay Hydro presents that the investments related to the legacy RESOP facilities (10M5 and 10M8 feeders) should be funded in accordance with the mechanism approved for 'enhancements' (as defined in the pre October 21, 2009 Distribution System Code[10,11]). Future

[10] Pre-October 21, 2009 Definition of "Enhancement" per the Distribution System Code; "enhancement means a modification to an existing distribution system that is made for purposes of improving system operating characteristics such as reliability or power quality or for relieving system capacity constraints resulting for example, from general load growth".

[11] Pre-October 21, 2009 Scope of "Enhancement" per the Distribution System Code; "A distributor shall continue to plan and build the distribution system for reasonable forecast load growth. A distributor may perform enhancements to its distribution system for purposes of improving system operating characteristics or for relieving system capacity constraints. In determining system enhancements to be performed on its distribution system, a distributor shall consider the following;

- Good utility practice;
- Improvement of the system to either meet or maintain required performance indices;
- Current levels of customer service and reliability and potential improvement from the enhancement; and,

investments, beyond the 'enhancements' described above, will take place in response to projects developed under the FIT Program and will be eligible for the Board's external cost recovery mechanism for Renewable Enabling Improvements.

Based on the instruction of EB-2009-0349[12], Thunder Bay Hydro intends to recover the Renewable Enabling Improvement Costs as determined by a basic direct benefit assessment. As such, the percentages approved within filing EB-2009-0096[13] have been applied here.

The allocation of such costs is as follows;

- 6% of total investment – responsibility of the Thunder Bay Hydro customers
- 94% of total investment allocated to electricity customers in the province and recovered via an external funding mechanism.

- costs to customers associated with distribution reliability and potential improvement from the enhancement.

[12] Excerpt from EB-2009-0349; "…*distributors that file a Basic GEA Plan will be permitted to undertake a basic (i.e., standardized) direct benefit assessment…*"

[13] 2009 Hydro One Distribution Rate application which contained a detailed direct benefit assessment, the outcome of which was determined to provide an appropriate estimate of direct benefits for those distributors conducting a basic direct benefit assessment.

Table 9 (following) summarizes the 2012 and 2013 cost recovery strategy for Thunder Bay Hydro's investments related to enabling renewable generation;

Year	2012	2013	2013
Gross Investment	$387,154	193,577	$387,154
Activity Definition (by the DSC)	"Enhancement"	"Enhancement"	"Renewable Enabling Improvement"
External Funding	$0	$0	$363,925
Funded by Thunder Bay Hydro Rate Base	$387,154	$193,577	$23,229
Number of Reclosers	6	3	6
Average Cost/Recloser	$64,526	$64,526	$64,526

Table 9 - Cost Distribution of Thunder Bay Hydro System Developments

In summary, of the 6 reclosers to be purchased for feeder 10M6 that will be considered a renewable enabling improvement in 2013, Thunder Bay Hydro is applying to obtain provincial funding through the basic direct benefit assessment of an REI capital investment of $363,925, with the remaining balance to be deferred in Thunder Bay Hydro's Account 1531 Renewable Connection Capital Deferral Account. . Thunder Bay Hydro plans to obtain a prudence review of this account with the Board once all renewable generation connections costs have been incurred. Further detail and the calculation of the funding adder is provided in Thunder Bay Hydro's 2013 rate application.

Account 1531 was authorized to include the costs associated with the Green Energy and Green Economy Act, 2009 requirements in respect of recording eligible expenditures for activities relating to expansions to connect renewable generation facilities and renewable enabling improvements. Since the 9 reclosers to be installed in 2012 and 2013 are associated with legacy RESOP projects (offer to connect was made prior to the October 21, 2009 DSC cost responsibility changes), Thunder Bay Hydro has included their purchase in its capital plan.

Note: At the time of writing Thunder Bay Hydro's GEA Plan, the costs were on a draft basis; however, since then, the costs have been adjusted such that the unit cost per recloser is $62,631 under MCGAAP.

Third Party Consultations

Thunder Bay Hydro has been in regular communication with Hydro One throughout the development and connection phases of renewable generation facilities TBS1 and TBS2. These consultations have included collaboration in the 'Connection Impact Assessment' phase, coordination of technical and construction requirements with respect to facility upgrades and protection schemes, and partnership throughout the commissioning of the projects.

Recently, Thunder Bay Hydro and Hydro One reached a consensus on tolerable fault levels which allowed for a significant increase in Birch TS' ability to accommodate further renewable generation.

Documentation (emails) supporting Thunder Bay Hydro's collaboration with Hydro One in these matters is available upon request.

APPENDIX 2-C
OPA Letter of Commitment

OPA Letter of Comment:

Thunder Bay Hydro Electricity Distribution Inc.

Basic Green Energy Act Plan

June 25, 2012

ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board (the "OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

Thunder Bay Hydro Electricity Distribution Inc. - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from Thunder Bay Hydro Electricity Distribution Inc. ("TBHEDI") dated June 12, 2012, and has provided its comments below.

OPA FIT/microFIT Applications Received

TBHEDI's GEA Plan indicates that there are 122 connected microFIT and 3 connected Capacity Allocation Except ("CAE") projects that have applied to connect to its distribution system. The Plan also indicates that there is 1 Capacity Application Required ("CAR") project that has the necessary LDC / Transmitter approvals required to proceed. This information is shown in section 2.1 *Present Levels of Renewable Generation Development* of the Plan.

According to the OPA's information, as of June 22, 2012, there are 121 connected microFIT projects, totalling 1.1 MW in TBHEDI's distribution system. There are also 18 Capacity Allocation Exempt ("CAE") applications and 1 Capacity Allocation Required ("CAR") application, for a total capacity of 16.9 MW, that have received FIT contracts in TBHEDI's service area.

In addition, 524 microFIT projects, with 4.8 MW of capacity have applied to connect in TBHEDI's service territory. The OPA has also received 5 FIT CAE applications and 12 CAR applications, totaling 125 MW of capacity, proposing to connect to TBHEDI's distribution system.

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Upstream Transmission Constraints

As noted in the Transmission Availability Table published by the OPA on April 5, 2012, the Northwest area is fully subscribed and does not have any capability to accommodate additional renewable generation. All renewable generation resources connecting to TBHEDI's system fall within the Northwest area. The area constraint is expected to limit the future uptake of large and small FIT renewable resources in TBHEDI's service territory. The East-West Tie expansion project, one of the 5 priority transmission projects in the government's Long-Term Energy Plan, is a major component in providing relief to the Northwest; however the project is not expected to be in service prior to 2017.

The updated Transmission Availability Table for Small FIT 2012 available on the OPA's FIT website as follows: http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website:
http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that TBHEDI's GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on Thunder Bay Hydro Electricity Distribution Inc.'s Basic GEA Plan.

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APPENDIX 2-D
Service Quality & Reliability Performance
(2009 – 2011)

CONNECTION OF NEW SERVICES - LOW VOLTAGE (LV) (2009-2011)

2011

	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
Jan	31	31	**100.00%**
Feb	51	51	**100.00%**
Mar	47	48	**97.92%**
Apr	50	51	**98.04%**
May	56	56	**100.00%**
Jun	75	75	**100.00%**
Jul	95	95	**100.00%**
Aug	92	92	**100.00%**
Sep	106	106	**100.00%**
Oct	100	100	**100.00%**
Nov	126	126	**100.00%**
Dec	67	67	**100.00%**
Annual Total	**896**	**898**	**99.80%**

2010

	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
Jan	33	33	**100.00%**
Feb	27	27	**100.00%**
Mar	64	65	**98.46%**
Apr	62	62	**100.00%**
May	73	73	**100.00%**
Jun	82	83	**98.80%**
Jul	69	69	**100.00%**
Aug	76	79	**96.20%**
Sep	77	80	**96.25%**
Oct	87	88	**98.86%**
Nov	110	112	**98.21%**
Dec	65	68	**95.59%**
Annual Total	**825**	**839**	**98.30%**

2009

	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
Jan	5	5	**100.00%**
Feb	1	1	**100.00%**
Mar	2	3	**66.67%**
Apr	6	6	**100.00%**
May	9	9	**100.00%**
Jun	9	9	**100.00%**
Jul	19	20	**95.00%**
Aug	23	26	**88.46%**
Sep	22	24	**91.67%**
Oct	38	41	**92.68%**
Nov	44	45	**97.78%**
Dec	22	22	**100.00%**
Annual Total	**200**	**211**	**94.80%**

CONNECTION OF NEW SERVICES - HIGH VOLTAGE (HV) (2009-2011)

2011

	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
Jan	2	2	**100.00%**
Feb	3	3	**100.00%**
Mar	1	1	**100.00%**
Apr	0	0	**0.00%**
May	1	1	**100.00%**
Jun	1	1	**100.00%**
Jul	0	0	**0.00%**
Aug	2	2	**100.00%**
Sep	7	7	**100.00%**
Oct	0	0	**0.00%**
Nov	2	2	**100.00%**
Dec	4	4	**100.00%**
Annual Total	**23**	**23**	**100.00%**

2010

	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
Jan	1	1	**100.00%**
Feb	0	0	**0.00%**
Mar	1	1	**100.00%**
Apr	1	1	**100.00%**
May	2	2	**100.00%**
Jun	1	1	**100.00%**
Jul	1	1	**100.00%**
Aug	6	6	**100.00%**
Sep	1	1	**100.00%**
Oct	2	2	**100.00%**
Nov	2	2	**100.00%**
Dec	3	3	**100.00%**
Annual Total	**21**	**21**	**100.00%**

2009

	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
Jan	0	0	**0.00%**
Feb	0	0	**0.00%**
Mar	1	1	**100.00%**
Apr	0	0	**0.00%**
May	0	0	**0.00%**
Jun	1	1	**100.00%**
Jul	2	2	**100.00%**
Aug	3	3	**100.00%**
Sep	2	2	**100.00%**
Oct	1	1	**100.00%**
Nov	0	0	**0.00%**
Dec	1	1	**100.00%**
Annual Total	**11**	**11**	**100.00%**

APPOINTMENT SCHEDULING (2009-2011)

2011

	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
Jan	91	91	**100.00%**
Feb	121	121	**100.00%**
Mar	147	148	**99.32%**
Apr	280	281	**99.64%**
May	714	817	**87.39%**
Jun	440	596	**73.83%**
Jul	426	549	**77.60%**
Aug	614	614	**100.00%**
Sep	580	581	**99.83%**
Oct	546	549	**99.45%**
Nov	354	356	**99.44%**
Dec	113	114	**99.12%**
Annual Total	**4,426**	**4,817**	**91.90%**

2010

	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
Jan	131	132	**99.24%**
Feb	235	236	**99.58%**
Mar	480	483	**99.38%**
Apr	747	764	**97.77%**
May	908	916	**99.13%**
Jun	825	833	**99.04%**
Jul	597	600	**99.50%**
Aug	549	554	**99.10%**
Sep	578	581	**99.48%**
Oct	407	412	**98.79%**
Nov	367	370	**99.19%**
Dec	160	160	**100.00%**
Annual Total	**5,984**	**6,041**	**99.10%**

2009

	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
Jan	14	14	**100.00%**
Feb	1	1	**100.00%**
Mar	17	17	**100.00%**
Apr	27	27	**100.00%**
May	39	39	**100.00%**
Jun	32	32	**100.00%**
Jul	36	36	**100.00%**
Aug	9	9	**100.00%**
Sep	27	27	**100.00%**
Oct	15	15	**100.00%**
Nov	13	13	**100.00%**
Dec	9	9	**100.00%**
Annual Total	**239**	**239**	**100.00%**

APPOINTMENTS MET (2009-2011)

2011

	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
Jan	91	91	**100.00%**
Feb	121	121	**100.00%**
Mar	147	148	**99.32%**
Apr	280	281	**99.64%**
May	714	817	**87.39%**
Jun	440	596	**73.83%**
Jul	426	549	**77.60%**
Aug	614	614	**100.00%**
Sep	580	581	**99.83%**
Oct	546	549	**99.45%**
Nov	354	356	**99.44%**
Dec	113	114	**99.12%**
Annual Total	**4,426**	**4,817**	**91.90%**

2010

	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
Jan	131	132	**99.24%**
Feb	235	236	**99.58%**
Mar	480	483	**99.38%**
Apr	747	764	**97.77%**
May	908	916	**99.13%**
Jun	825	833	**99.04%**
Jul	597	600	**99.50%**
Aug	549	554	**99.10%**
Sep	578	581	**99.48%**
Oct	407	412	**98.79%**
Nov	367	370	**99.19%**
Dec	160	160	**100.00%**
Annual Total	**5,984**	**6,041**	**99.10%**

2009

	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
Jan	14	14	**100.00%**
Feb	1	1	**100.00%**
Mar	17	17	**100.00%**
Apr	27	27	**100.00%**
May	39	39	**100.00%**
Jun	32	32	**100.00%**
Jul	36	36	**100.00%**
Aug	9	9	**100.00%**
Sep	27	27	**100.00%**
Oct	15	15	**100.00%**
Nov	13	13	**100.00%**
Dec	9	9	**100.00%**
Annual Total	**239**	**239**	**100.00%**

RESCHEDULING A MISSED APPOINTMENT (2009-2011)

2011

	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
Jan	0	0	**0.00%**
Feb	0	0	**0.00%**
Mar	1	1	**100.00%**
Apr	0	0	**0.00%**
May	0	0	**0.00%**
Jun	0	0	**0.00%**
Jul	0	0	**0.00%**
Aug	0	0	**0.00%**
Sep	0	0	**0.00%**
Oct	0	0	**0.00%**
Nov	0	0	**0.00%**
Dec	0	0	**0.00%**
Annual Total	**1**	**1**	**100.00%**

2010

	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
Jan	0	0	**0.00%**
Feb	1	1	**100.00%**
Mar	1	1	**100.00%**
Apr	1	1	**100.00%**
May	1	1	**100.00%**
Jun	1	1	**100.00%**
Jul	1	1	**100.00%**
Aug	1	1	**100.00%**
Sep	1	1	**100.00%**
Oct	1	1	**100.00%**
Nov	0	0	**0.00%**
Dec	0	0	**0.00%**
Annual Total	**9**	**9**	**100.00%**

2009

	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
Jan	0	0	**0.00%**
Feb	0	0	**0.00%**
Mar	0	0	**0.00%**
Apr	0	0	**0.00%**
May	0	0	**0.00%**
Jun	1	1	**100.00%**
Jul	0	0	**0.00%**
Aug	0	0	**0.00%**
Sep	2	2	**100.00%**
Oct	0	0	**0.00%**
Nov	0	0	**0.00%**
Dec	0	0	**0.00%**
Annual Total	**3**	**3**	**100.00%**

TELEPHONE ACCESSIBILITY (2009-2011)

2011

	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
Jan	3,473	3,720	**93.36%**
Feb	3,146	3,366	**93.46%**
Mar	4,147	4,570	**90.74%**
Apr	3,648	3,928	**92.87%**
May	3,974	4,297	**92.48%**
Jun	4,646	5,077	**91.51%**
Jul	4,555	5,007	**90.97%**
Aug	4,068	4,543	**89.54%**
Sep	3,693	3,972	**92.98%**
Oct	3,711	4,032	**92.04%**
Nov	3,471	3,855	**90.04%**
Dec	2,668	2,887	**92.41%**
Annual Total	**45,200**	**49,254**	**91.80%**

2010

	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
Jan	4,095	4,394	**93.20%**
Feb	3,857	4,056	**95.09%**
Mar	4,748	5,083	**93.41%**
Apr	4,406	4,861	**90.64%**
May	4,332	4,682	**92.52%**
Jun	4,747	5,238	**90.63%**
Jul	4,587	4,930	**93.04%**
Aug	4,452	4,780	**93.14%**
Sep	4,508	4,861	**92.74%**
Oct	4,501	4,979	**90.40%**
Nov	3,851	4,124	**93.38%**
Dec	2,912	3,033	**96.01%**
Annual Total	**50,996**	**55,021**	**92.70%**

2009

	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
Jan	4,061	4,202	**96.64%**
Feb	3,795	3,949	**96.10%**
Mar	4,682	4,991	**93.81%**
Apr	4,480	4,865	**92.09%**
May	4,390	4,708	**93.25%**
Jun	4,933	5,304	**93.01%**
Jul	4,615	5,077	**90.90%**
Aug	4,546	4,845	**93.83%**
Sep	5,630	6,606	**85.23%**
Oct	4,612	4,940	**93.36%**
Nov	4,420	4,766	**92.74%**
Dec	3,360	3,522	**95.40%**
Annual Total	**53,524**	**57,775**	**92.60%**

TELEPHONE CALL ABANDON RATE (2009-2011)

2011

	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
Jan	19	3,720	**0.51%**
Feb	18	3,366	**0.53%**
Mar	49	4,570	**1.07%**
Apr	32	3,928	**0.81%**
May	45	4,297	**1.05%**
Jun	44	5,077	**0.87%**
Jul	62	5,007	**1.24%**
Aug	71	4,543	**1.56%**
Sep	31	3,972	**0.78%**
Oct	33	4,032	**0.82%**
Nov	49	3,855	**1.27%**
Dec	34	2,887	**1.18%**
Annual Total	**487**	**49,254**	**1.00%**

2010

	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
Jan	55	4,861	**1.13%**
Feb	38	4,682	**0.81%**
Mar	48	5,238	**0.92%**
Apr	32	4,930	**0.65%**
May	28	4,780	**0.59%**
Jun	33	4,861	**0.68%**
Jul	46	4,979	**0.92%**
Aug	23	4,124	**0.56%**
Sep	31	4,394	**0.71%**
Oct	18	4,056	**0.44%**
Nov	8	3,033	**0.26%**
Dec	27	5,083	**0.53%**
Annual Total	**387**	**55,021**	**0.70%**

2009

	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
Jan	71	4,202	**1.69%**
Feb	64	3,949	**1.62%**
Mar	88	4,991	**1.76%**
Apr	100	4,865	**2.06%**
May	94	4,708	**2.00%**
Jun	108	5,304	**2.04%**
Jul	115	5,077	**2.27%**
Aug	73	4,845	**1.51%**
Sep	243	6,606	**3.68%**
Oct	95	4,940	**1.92%**
Nov	77	4,766	**1.62%**
Dec	62	3,522	**1.76%**
Annual Total	**1,190**	**57,775**	**2.10%**

WRITTEN RESPONSES TO ENQUIRIES (2009-2011)

2011

	# of written responses provided within 10 days	# of qualified enquiries received	% written responses provided within 10 days
Jan	11	12	**91.67%**
Feb	16	20	**80.00%**
Mar	24	24	**100.00%**
Apr	22	22	**100.00%**
May	15	17	**88.24%**
Jun	22	22	**100.00%**
Jul	31	31	**100.00%**
Aug	36	36	**100.00%**
Sep	20	20	**100.00%**
Oct	34	35	**97.14%**
Nov	27	27	**100.00%**
Dec	30	30	**100.00%**
Annual Total	**288**	**296**	**97.30%**

2010

	# of written responses provided within 10 days	# of qualified enquiries received	% written responses provided within 10 days
Jan	18	18	**100.00%**
Feb	26	27	**96.30%**
Mar	19	19	**100.00%**
Apr	6	6	**100.00%**
May	24	24	**100.00%**
Jun	5	5	**100.00%**
Jul	6	6	**100.00%**
Aug	18	21	**85.71%**
Sep	17	17	**100.00%**
Oct	16	16	**100.00%**
Nov	13	13	**100.00%**
Dec	11	11	**100.00%**
Annual Total	**179**	**183**	**97.80%**

2009

	# of written responses provided within 10 days	# of qualified enquiries received	% written responses provided within 10 days
Jan	1	1	**100.00%**
Feb	3	3	**100.00%**
Mar	17	17	**100.00%**
Apr	12	12	**100.00%**
May	7	7	**100.00%**
Jun	16	17	**94.12%**
Jul	18	18	**100.00%**
Aug	5	5	**100.00%**
Sep	14	14	**100.00%**
Oct	14	14	**100.00%**
Nov	20	20	**100.00%**
Dec	8	8	**100.00%**
Annual Total	**135**	**136**	**99.30%**

EMERGENCY RESPONSE URBAN (2009-2011)

2011

	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
Jan	3	3	**100.00%**
Feb	2	2	**100.00%**
Mar	4	4	**100.00%**
Apr	5	5	**100.00%**
May	9	9	**100.00%**
Jun	3	3	**100.00%**
Jul	17	18	**94.44%**
Aug	12	12	**100.00%**
Sep	10	12	**83.33%**
Oct	7	7	**100.00%**
Nov	5	5	**100.00%**
Dec	6	6	**100.00%**
Annual Total	**83**	**86**	**96.50%**

2010

	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
Jan	7	7	**100.00%**
Feb	1	1	**100.00%**
Mar	10	10	**100.00%**
Apr	11	11	**100.00%**
May	7	7	**100.00%**
Jun	8	9	**88.89%**
Jul	8	8	**100.00%**
Aug	7	7	**100.00%**
Sep	5	6	**83.33%**
Oct	12	12	**100.00%**
Nov	6	7	**85.71%**
Dec	6	6	**100.00%**
Annual Total	**88**	**91**	**96.70%**

2009

	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
Jan	4	4	**100.00%**
Feb	7	7	**100.00%**
Mar	3	3	**100.00%**
Apr	5	5	**100.00%**
May	5	5	**100.00%**
Jun	3	3	**100.00%**
Jul	9	9	**100.00%**
Aug	4	4	**100.00%**
Sep	16	19	**84.21%**
Oct	1	1	**100.00%**
Nov	2	2	**100.00%**
Dec	5	5	**100.00%**
Annual Total	**64**	**67**	**95.50%**

EMERGENCY RESPONSE RURAL (2009-2011)

2011

	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
Jan	0	0	**0.00%**
Feb	0	0	**0.00%**
Mar	0	0	**0.00%**
Apr	2	2	**100.00%**
May	1	1	**100.00%**
Jun	1	1	**100.00%**
Jul	0	0	**0.00%**
Aug	2	2	**100.00%**
Sep	2	2	**100.00%**
Oct	1	1	**100.00%**
Nov	1	1	**100.00%**
Dec	1	1	**100.00%**
Annual Total	**11**	**11**	**100.00%**

2010

	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
Jan	2	2	**100.00%**
Feb	0	0	**0.00%**
Mar	2	2	**100.00%**
Apr	3	3	**100.00%**
May	1	1	**100.00%**
Jun	5	5	**100.00%**
Jul	6	6	**100.00%**
Aug	1	1	**100.00%**
Sep	4	4	**100.00%**
Oct	5	6	**83.33%**
Nov	1	2	**50.00%**
Dec	1	1	**100.00%**
Annual Total	**31**	**33**	**93.94%**

2009

	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
Jan	2	2	**100.00%**
Feb	0	0	**0.00%**
Mar	1	1	**100.00%**
Apr	2	2	**100.00%**
May	2	2	**100.00%**
Jun	1	1	**100.00%**
Jul	3	3	**100.00%**
Aug	0	0	**0.00%**
Sep	5	5	**100.00%**
Oct	1	1	**100.00%**
Nov	1	1	**100.00%**
Dec	1	1	**100.00%**
Annual Total	**19**	**19**	**100.00%**

SERVICE RELIABILITY INDICES (2009-2011)

2011

	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	637	380	49,588	**0.01**	**0.01**	**1.68**
Feb	1,254	1,933	49,606	**0.03**	**0.04**	**0.65**
Mar	11,426	14,303	49,601	**0.23**	**0.29**	**0.80**
Apr	9,717	17,701	49,587	**0.20**	**0.36**	**0.55**
May	14,096	27,470	49,577	**0.28**	**0.55**	**0.51**
Jun	6,332	20,794	49,604	**0.13**	**0.42**	**0.30**
Jul	65,853	71,673	49,621	**1.33**	**1.44**	**0.92**
Aug	8,028	7,134	49,628	**0.16**	**0.14**	**1.13**
Sep	5,585	9,601	49,675	**0.11**	**0.19**	**0.58**
Oct	12,092	8,837	49,721	**0.24**	**0.18**	**1.37**
Nov	2,325	5,877	49,764	**0.05**	**0.12**	**0.40**
Dec	1,094	2,975	49,824	**0.02**	**0.06**	**0.37**
Annual Total	**138,439**	**188,678**	**49,650**	**2.79**	**3.80**	**0.73**

2010

	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	739	1,228	49,438	**0.01**	**0.02**	**0.60**
Feb	14,416	12,323	49,454	**0.29**	**0.25**	**1.17**
Mar	2,136	10,776	49,446	**0.04**	**0.22**	**0.20**
Apr	6,556	15,849	49,382	**0.13**	**0.32**	**0.41**
May	3,744	14,611	49,375	**0.08**	**0.30**	**0.26**
Jun	13,882	42,644	49,397	**0.28**	**0.86**	**0.33**
Jul	20,945	40,582	49,399	**0.42**	**0.82**	**0.52**
Aug	12,948	21,104	49,413	**0.26**	**0.43**	**0.61**
Sep	11,308	17,208	49,422	**0.23**	**0.35**	**0.66**
Oct	50,716	34,682	49,475	**1.03**	**0.70**	**1.46**
Nov	4,363	6,845	49,539	**0.09**	**0.14**	**0.64**
Dec	3,548	7,435	49,607	**0.07**	**0.15**	**0.48**
Annual Total	**145,301**	**225,287**	**49,446**	**2.94**	**4.56**	**0.64**

2009

	Total Customer Hours of Interruptions (1)	Total Customer Interruptions (2)	Total # of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	1,128	2,973	49,365	**0.02**	**0.06**	**0.38**
Feb	907	2,877	49,361	**0.02**	**0.06**	**0.32**
Mar	4,731	5,901	49,635	**0.10**	**0.12**	**0.80**
Apr	3,794	10,969	49,218	**0.08**	**0.22**	**0.35**
May	4,430	13,009	49,256	**0.09**	**0.26**	**0.34**
Jun	2,941	8,952	49,243	**0.06**	**0.18**	**0.33**
Jul	4,508	9,443	49,264	**0.09**	**0.19**	**0.48**
Aug	7,752	2,707	49,264	**0.16**	**0.05**	**2.86**
Sep	101,890	69,492	49,296	**2.07**	**1.41**	**1.47**
Oct	75,801	57,793	49,372	**1.54**	**1.17**	**1.31**
Nov	6,789	8,380	49,388	**0.14**	**0.17**	**0.81**
Dec	2,419	10,428	49,456	**0.05**	**0.21**	**0.23**
Annual Total	**217,090**	**202,924**	**49,343**	**4.40**	**4.11**	**1.07**

LOSS OF SUPPLY ADJUSTED SERVICE RELIABILITY INDICES (2009-2011)

2011

	Adjusted Customer Hours of Interruptions (1)	Adjusted Customer Interruptions (2)	Total # of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	367	349	49,588	**0.01**	**0.01**	**1.05**
Feb	1,254	1,933	49,606	**0.03**	**0.04**	**0.65**
Mar	11,426	14,303	49,601	**0.23**	**0.29**	**0.80**
Apr	9,677	17,693	49,587	**0.20**	**0.36**	**0.55**
May	13,736	20,256	49,577	**0.28**	**0.41**	**0.68**
Jun	6,332	20,794	49,604	**0.13**	**0.42**	**0.30**
Jul	65,853	71,673	49,621	**1.33**	**1.44**	**0.92**
Aug	8,028	7,134	49,628	**0.16**	**0.14**	**1.13**
Sep	5,585	9,601	49,675	**0.11**	**0.19**	**0.58**
Oct	12,092	8,837	49,721	**0.24**	**0.18**	**1.37**
Nov	2,325	5,877	49,764	**0.05**	**0.12**	**0.40**
Dec	1,094	2,975	49,824	**0.02**	**0.06**	**0.37**
Annual Total	**137,769**	**181,425**	**49,650**	**2.77**	**3.65**	**0.76**

2010

	Adjusted Customer Hours of Interruptions (1)	Adjusted Customer Interruptions (2)	Total # of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	739	1,228	49,438	**0.01**	**0.02**	**0.60**
Feb	975	2,714	49,454	**0.02**	**0.05**	**0.36**
Mar	2,136	10,776	49,446	**0.04**	**0.22**	**0.20**
Apr	6,504	15,836	49,382	**0.13**	**0.32**	**0.41**
May	3,029	4,746	49,375	**0.06**	**0.10**	**0.64**
Jun	11,557	18,728	49,397	**0.23**	**0.38**	**0.62**
Jul	20,754	40,544	49,399	**0.42**	**0.82**	**0.51**
Aug	12,948	21,104	49,413	**0.26**	**0.43**	**0.61**
Sep	11,308	17,208	49,422	**0.23**	**0.35**	**0.66**
Oct	50,716	34,682	49,475	**1.03**	**0.70**	**1.46**
Nov	4,363	6,845	49,539	**0.09**	**0.14**	**0.64**
Dec	3,548	7,435	49,607	**0.07**	**0.15**	**0.48**
Annual Total	**128,577**	**181,846**	**49,446**	**2.60**	**3.68**	**0.71**

2009

	Adjusted Customer Hours of Interruptions (1)	Adjusted Customer Interruptions (2)	Total # of Customers (3)	SAIDI (4) (1) / (3)	SAIFI (5) (2) / (3)	CAIDI (4) / (5)
Jan	1,128	2,973	49,365	**0.02**	**0.06**	**0.38**
Feb	907	2,877	49,361	**0.02**	**0.06**	**0.32**
Mar	4,731	5,901	49,635	**0.10**	**0.12**	**0.80**
Apr	3,794	10,969	49,218	**0.08**	**0.22**	**0.35**
May	4,430	13,009	49,256	**0.09**	**0.26**	**0.34**
Jun	2,941	8,952	49,243	**0.06**	**0.18**	**0.33**
Jul	4,508	9,443	49,264	**0.09**	**0.19**	**0.48**
Aug	7,752	2,707	49,264	**0.16**	**0.05**	**2.86**
Sep	101,611	69,579	49,296	**2.06**	**1.41**	**1.46**
Oct	17,454	34,001	49,372	**0.35**	**0.69**	**0.51**
Nov	6,789	8,380	49,388	**0.14**	**0.17**	**0.81**
Dec	2,419	10,428	49,456	**0.05**	**0.21**	**0.23**
Annual Total	**158,464**	**179,219**	**49,343**	**3.21**	**3.63**	**0.88**

MOMENTARY AVERAGE INTERRUPTION FREQUENCY INDEX (2009-2011)

2011			
	Momentary Interruption (1)	Number of Customers Served (2)	MAIFI (1)/(2)
Jan	14	49,588	**0.00**
Feb	5,405	49,606	**0.11**
Mar	15,985	49,601	**0.32**
Apr	15,066	49,587	**0.30**
May	6,653	49,577	**0.13**
Jun	34,613	49,604	**0.70**
Jul	40,748	49,621	**0.82**
Aug	18,966	49,628	**0.38**
Sep	30,078	49,675	**0.61**
Oct	10,604	49,721	**0.21**
Nov	3,778	49,764	**0.08**
Dec	4,759	49,824	**0.10**
Annual Total	**186,669**	**49,650**	**3.76**

2010			
	Momentary Interruption (1)	Number of Customers Served (2)	MAIFI (1)/(2)
Jan	3,755	49,438	**0.08**
Feb	6,709	49,454	**0.14**
Mar	11,075	49,446	**0.22**
Apr	11,598	49,382	**0.23**
May	24,664	49,375	**0.50**
Jun	41,520	49,397	**0.84**
Jul	38,299	49,399	**0.78**
Aug	22,717	49,413	**0.46**
Sep	14,037	49,422	**0.28**
Oct	5,777	49,475	**0.12**
Nov	29	49,539	**0.00**
Dec	10,221	49,607	**0.21**
Annual Total	**190,401**	**49,446**	**3.85**

2009			
	Momentary Interruption (1)	Number of Customers Served (2)	MAIFI (1)/(2)
Jan	4,101	49,365	**0.08**
Feb	3,169	49,361	**0.06**
Mar	7,390	49,635	**0.15**
Apr	6,822	49,218	**0.14**
May	6,679	49,256	**0.14**
Jun	14,729	49,243	**0.30**
Jul	44,387	49,264	**0.90**
Aug	34,958	49,264	**0.71**
Sep	67,642	49,296	**1.37**
Oct	14,428	49,372	**0.29**
Nov	5,404	49,388	**0.11**
Dec	413	49,456	**0.01**
Annual Total	**210,122**	**49,343**	**4.26**

RECONNECTION PERFORMANCE STANDARD (2009-2011)

2011

	Number of Reconnections Completed in 2 Business Days for Customers Disconnected for Non-Payment	Number of Reconnections for Customers Disconnected for Non-Payment	% of Reconnections Completed in 2 Business Days for Customers Disconnected for Non-Payment
Jan	12	12	**100.00%**
Feb	30	30	**100.00%**
Mar	36	36	**100.00%**
Apr	50	50	**100.00%**
May	42	42	**100.00%**
Jun	31	31	**100.00%**
Jul	53	53	**100.00%**
Aug	75	75	**100.00%**
Sep	45	45	**100.00%**
Oct	43	43	**100.00%**
Nov	42	42	**100.00%**
Dec	21	21	**100.00%**
Annual Total	**480**	**480**	**100.00%**

Exhibit	Tab	Schedule	Appendix	Contents
3 – Operating Revenue				
	1	1		Overview of Operating Revenue
	2	1		Weather Normalized Load and Customer/Connection Forecast
	3	1		Operating Revenue Variance Analysis
		2		Transformer Allowance
		3		Variance Analysis on other Distribution Revenue
			3-A	Monthly Data Used for Regression Analysis
			3-B	OPA Final Evaluation

OVERVIEW OF OPERATING REVENUE

This Exhibit provides the details of Thunder Bay Hydro's operating revenue for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, the 2012 Bridge Year and the 2013 Test Year. This Exhibit also provides a detailed variance analysis by rate class of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

Thunder Bay Hydro is proposing a total Service Revenue Requirement of $21,652,791 for the 2013 Test Year. This amount includes a Base Revenue Requirement of $19,901,055 plus revenue offsets of $1,751,736 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented below in Table 3-1.1 and provides a comparison of total revenues from the 2009 OEB approved year to the 2013 Test Year.

Throughput Revenue

Information related to Thunder Bay Hydro's throughput revenue includes details on the weather normalized load forecasting methodology reflecting expected CDM results, a forecast of customers by rate class based on the historical number of customers billed throughout the year, and known economic conditions.

A detailed variance analysis on the historical throughput revenue is also provided in this Exhibit.

Other Revenue

Other revenues include but are not limited to, Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. This is shown in Table 3-1.1 below.

A detailed variance analysis on other revenue is set out later on this Exhibit.

Table 3-1.1 - Other Operating Revenue

USoA #	USoA Description	2009 Actual	2010 Actual	2011 Actual[2]	Bridge Year[3]	Test Year	Test Year
					2012	2013	2013
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MCGAAP
4235	Specific Service Charges	$ (320,631)	$ (322,428)	$ (270,471)	$ (274,216)	$ (267,807)	$ (267,807)
4225	Late Payment Charges	$ (289,447)	$ (261,868)	$ (297,478)	$ (297,000)	$ (297,000)	$ (297,000)
4080-2	SSS Revenue	$ (128,694)	$ (127,920)	$ (131,704)	$ (131,340)	$ (131,340)	$ (131,340)
4082	RS Rev	$ (75,266)	$ (66,688)	$ (55,954)	$ (59,150)	$ (59,150)	$ (59,150)
4084	Serv Tx Requests	$ (1,681)	$ (5,629)	$ (1,786)	$ (1,900)	$ (1,900)	$ (1,900)
4090	Electric Services Incidental to Energy Sales						
4205	Interdepartmental Rents					$ -	$ -
4210	Rent from Electric Property	$ (460,835)	$ (462,179)	$ (477,108)	$ (471,000)	$ (471,000)	$ (471,000)
4215	Other Utility Operating Income					$ -	$ -
4220	Other Electric Revenues	$ (93,337)	$ (139,302)	$ (202,431)	$ (168,726)	$ (180,818)	$ (180,818)
4240	Provision for Rate Refunds	$ 361,129	$ -	$ -	$ -	$ -	$ -
4245	Government Assistance Directly Credited to Income				$ -	$ -	$ (12,712)
4305	Regulatory Debits					$ -	$ -
4310	Regulatory Credits					$ -	$ -
4315	Revenues from Electric Plant Leased to Others					$ -	$ -
4324	SPC Recovery		$ (224,891)	$ (164,329)		$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.					$ -	$ -
4330	Costs and Expenses of Merchandising, Jobbing, Etc					$ -	$ -
4335	Profits and Losses from Financial Instrument Hedges					$ -	$ -
4340	Profits and Losses from Financial Instrument Investments					$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant					$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant					$ -	$ -
4355	Gain on Disposition of Utility and Other Property	$ (14,336)	$ (400)	$ (26,513)	$ 12,200	$ (49,850)	$ 14,120
4360	Loss on Disposition of Utility and Other Property						
4362	Loss from Retirement of Utility and Other Property					$ 30,000	$ 30,000
4365	Gains from Disposition of Allowances for Emission					$ -	$ -
4370	Losses from Disposition of Allowances for Emission					$ -	$ -
4375	Revenues from Non-Utility Operations	$ (680,002)	$ (656,246)	$ (739,783)	$ (879,343)	$ (668,839)	$ (668,839)
4380	Expenses of Non-Utility Operations	$ 646,324	$ 658,682	$ 739,003	$ 890,954	$ 677,224	$ 677,101
4385	Expenses of Non-Utility Operations					$ -	$ -
4390	Miscellaneous Non-Operating Income	$ (182,056)	$ (251,896)	$ (277,307)	$ (278,000)	$ (272,000)	$ (272,000)
4395	Rate-Payer Benefit Including Interest					$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization					$ -	$ -
4405	Interest and Dividend Income	$ (159,335)	$ (178,369)	$ (747,158)	$ 99,807	$ (110,390)	$ (110,390)
4415	Equity in Earnings of Subsidiary Companies					$ -	$ -
Specific Service Charges		$ (320,631)	$ (322,428)	$ (270,471)	$ (274,216)	$ (267,807)	$ (267,807)
Late Payment Charges		$ (289,447)	$ (261,868)	$ (297,478)	$ (297,000)	$ (297,000)	$ (297,000)
Other Operating Revenues		$ (398,683)	$ (801,718)	$ (868,981)	$ (832,116)	$ (844,208)	$ (856,920)
Other Income or Deductions		$ (389,405)	$ (653,120)	$ (1,216,087)	$ (154,382)	$ (393,855)	$ (330,008)
Total		$ (1,398,167)	$ (2,039,134)	$ (2,653,018)	$ (1,557,714)	$ (1,802,870)	$ (1,751,736)

WEATHER NORMALIZED LOAD AND CUSTOMER/CONNECTION FORECAST

The purpose of this evidence is to present the process used by Thunder Bay Hydro to prepare the weather normalized load and customer/connection forecast used to design the proposed 2013 electricity distribution rates. Please note that the Monthly Data used for Regression Analysis is found in Appendix 3-A.

Thunder Bay Hydro has used a similar regression analysis methodology used by a number of distributors in previous cost of service rate applications to determine a prediction model. However, Thunder Bay Hydro has conducted the regression analysis on an individual rate class basis. Thunder Bay Hydro estimated the amount consumed in a month by rate class using an equation to prorate billing that was used in the process for unbilled revenue. Based on the R square and Adjusted R square values shown in Table 3-2.1, Thunder Bay Hydro concluded using the equation resulting from the Residential, General Service < 50 kW and General Service > 50 to 999 kW rate class regression analyses would provide a prediction formula that was as good or better as the prediction equation from the power purchased method. In addition, the 2013 total kWh load forecast from the individual rate class analysis is almost 1.4% higher than the total kWh load forecast from the power purchased method.

Table 3-2.1: R Square and Adjusted R Square Values for Individual Class Regression Analysis

Class	R Square	Adjusted R Square
Residential	95%	95%
General Service < 50 kW	77%	76%
General Service > 50 to 999 kW	94%	94%

The R square and Adjusted R square values for the power purchased method were 94% and 95%, respectively.

With regards to the GS > 1000 kW class, the results of the regression analysis for this class are shown in Table 3-2.2.

Table 3-2.2: General Service > 1000 kW Regression Analysis Results

R Square	59%	
Adjusted R Square	57%	
Variable	**Coefficients**	**t Stat**
Heating Degree Days	39	0.07
Cooling Degree Days	4,735	0.39
Number of Days in Month	502,240	2.84
Spring Fall Flag	203,365	0.66
CDM Activity	(320)	(5.80)
Ontario Real GDP Monthly %	219,918	13.61
Number of Customers	(86,239)	(1.10)
Number of Peak Hours	8,719	1.03
Intercept	(29,381,782)	(5.25)

The above table outlines a low R square and Adjusted R square values but also shows a t Stat value for Heating Degree Days and Cooling Degree Days less than the absolute value of two. This indicates these variables are not statistically significant and would not be contributing variables to a prediction formula for this class. It also suggests to Thunder Bay Hydro that the General Service > 1000 kW class is not weather sensitive since Heating Degree Days and Cooling Degree Days, which are the typical weather related variables, would not be contributing variables to a prediction formula.

Thunder Bay Hydro proposes to use a separate multi factor regression analysis for the Residential, General Service < 50 kW and General Service > 50 to 999 kW rate classes since these classes are weather sensitive. For all other classes which are not weather sensitive, the load forecast for these classes will be the forecasted average usage per customer/connection applied to the forecasted number of customer/connections for the class.

During the review of 2010 cost of service applications, Board staff and Interveners expressed concern that the regression analysis assigned coefficients to some variables that were counter intuitive. For example, the customer variables would have a negative coefficient assigned to it which meant as the number of customers increased the energy forecast decreased. 2010 applicants explained that this was related to the recent Conservation and Demand Management ("CDM") savings in the utility but in the view of Board staff and Interveners this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables

used in the load forecasting formula were not statistically significant and should not have been included in the equation. Thunder Bay Hydro has attempted to address these concerns in the load forecast used in this Application. Based on the discussion that follows, Thunder Bay Hydro submits that its load forecasting methodology is reasonable for the purposes of this Application.

Table 3-2.3, summarizes the material to support the weather normalized load forecast used by Thunder Bay Hydro in this Application.

Table 3-2.3: Billed Energy and Number of Customers / Connections by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Billed Energy (GWh)								
2009 Board Approved	350.2	144.3	305.3	194.5	10.6	0.1	1.8	1,006.8
2000 Actual	347.9	151.1	285.2	162.1	0.0	0.1	0.3	946.7
2001 Actual	350.1	149.2	286.8	158.1	0.0	0.1	0.3	944.7
2002 Actual	358.4	151.6	295.7	152.3	2.3	0.1	1.2	961.6
2003 Actual	362.1	145.4	301.0	171.8	10.7	0.1	1.7	992.8
2004 Actual	356.2	148.4	289.8	183.7	10.9	0.1	1.7	990.8
2005 Actual	356.0	147.4	302.1	214.1	10.9	0.1	1.7	1,032.3
2006 Actual	345.4	141.7	299.2	241.4	9.9	0.1	1.9	1,039.5
2007 Actual	347.7	140.8	299.0	230.9	10.9	0.1	2.0	1,031.5
2008 Actual	350.0	140.8	297.5	204.5	10.8	0.1	1.9	1,005.8
2009 Actual	345.1	137.5	290.8	189.8	11.6	0.1	2.0	976.8
2010 Actual	336.0	132.8	285.0	177.3	11.2	0.1	1.9	944.5
2011 Actual	337.6	135.7	288.4	183.2	11.2	0.1	2.0	958.2
2012 Bridge	**340.3**	**131.6**	**288.0**	**182.3**	**11.1**	**0.1**	**2.0**	**955.5**
2013 Test	**335.9**	**129.9**	**285.2**	**181.5**	**11.1**	**0.1**	**2.0**	**945.7**
Number of Customers/Connections								
2009 Board Approved	44,635	4,466	511	19	13,091	176	437	63,335
2000 Actual	43,694	4,464	490	18	0	93	427	49,186
2001 Actual	43,780	4,459	476	18	0	105	429	49,267
2002 Actual	43,923	4,430	482	18	12,637	87	430	62,007
2003 Actual	44,031	4,384	499	14	12,739	135	430	62,232
2004 Actual	44,154	4,416	467	19	12,769	140	431	62,395
2005 Actual	44,249	4,413	480	18	12,858	153	432	62,602
2006 Actual	44,345	4,315	493	18	12,962	164	428	62,724
2007 Actual	44,422	4,274	501	19	12,976	153	435	62,779
2008 Actual	44,570	4,258	507	19	13,135	150	457	63,096
2009 Actual	44,646	4,266	506	21	13,039	158	459	63,094
2010 Actual	44,766	4,307	507	20	13,170	167	469	63,405
2011 Actual	44,931	4,341	506	19	13,091	148	470	63,505
2012 Bridge	**45,044**	**4,335**	**507**	**19**	**13,135**	**149**	**475**	**63,665**
2013 Test	**45,158**	**4,330**	**507**	**19**	**13,180**	**151**	**481**	**63,827**

The information in the table above provides weather actual data from 2000 to 2011, while 2012 and 2013 are weather normalized for Residential, General Service < 50 kW and General Service > 50 to 999 kW classes. Thunder Bay Hydro does not have a process to properly adjust weather actual data to a weather normal basis. However, based on the process outlined

in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on an average basis and streetlight, sentinel lights and unmetered loads are measured as connections.

LOAD FORECAST AND METHODOLOGY

Billed kWh Load Forecast – Residential, General Service < 50 kW and General Service > 50 to 999 kW Classes

An equation to predict weather normalized billed energy for the Residential, General Service < 50 kW and General Service > 50 to 999 kW classes is developed using a multifactor regression model with independent variables that influence the monthly consumption in each class. The regression model uses monthly kWh and monthly values of independent variables from February 1999 to December 2011 to determine a prediction formula with coefficients for each independent variable. This provides 155 monthly data points which represent a reasonable data set for use in a regression analysis. Consistent with the approach used by many other distributors in their cost of service applications, Thunder Bay Hydro submits that it is appropriate to review the impact of weather over the period February 1999 to December 2011 and then determine the average weather conditions over this period which would be applied in the prediction formula to determine a weather normalized forecast. However, in accordance with the OEB's Filing Requirements, Thunder Bay Hydro has also provided a sensitivity analysis showing the impact on the 2013 billed forecast assuming weather normal conditions are based on a 10-year average and a 20-year trend of weather data.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The following outlines the prediction model used by Thunder Bay Hydro to predict weather normal billed values for Residential, General Service < 50 kW and General Service > 50 to 999 kW classes for 2012 and 2013:

Thunder Bay Hydro's Monthly Predicted Residential Billed kWh

= Heating Degree Days * 14,195
+ Cooling Degree Days * 34,410
+ Number of Days in the Month * 835,518
+ Spring Fall Flag * (889,871)
+ CDM Activity * (1.26)
+ Intercept of (2,222,087)

Thunder Bay Hydro's Monthly Predicted General Service < 50 kW Billed kWh
= Heating Degree Days * 4,308
+ Cooling Degree Days * 20,139
+ Number of Days in the Month * 164,058
+ Spring Fall Flag * (456,769)
+ CDM Activity * (5.17)
+ Intercept of 5,439,400

Thunder Bay Hydro's Monthly Predicted General Service > 50 to 999 kW Billed kWh
= Heating Degree Days * 9,133
+ Cooling Degree Days * 40,343
+ Number of Days in the Month * 392,929
+ Spring Fall Flag * (639,548)
+ CDM Activity * (3.63)
+ Ontario Real GDP Monthly * 22,719
+ Number of Customers * 5,040
+ Number of Peak Hours * 8,807
+ Intercept of 189,185

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years is provided in Appendix 2-B.

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 Thunder Bay Airport was used.

b) The calendar provided the months defined to be spring or fall (i.e. March to May and September to November), the number of days in the month and providing the basis to determine the number of peak hours in the month.

c) For 1999 to 2006 the source of data for the Ontario Real GDP information was the 2003 and 2008 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance. For 2007 and 2008, the source was the 2010 Ontario Economic Outlook and Fiscal Review - 2010 Fall Update. For 2009 to 2013, the 2011 Ontario Economic Outlook and Fiscal Review - 2011 Fall Update provided the Ontario Real GDP for those years. This information was only used for the General Service > 50 to 999 kW class.

d) The billing system provided historical monthly number of customers for the General Service > 50 to 999 kW class and the forecasted number of customers was based on the customer forecast discussed below.

e) The CDM activity variable has been determined for each class and is an estimated level of monthly activity in CDM. For each year the monthly values for the class specific CDM activity variable grow at constant value over the year. For the years 2006 to 2013, the addition of the monthly CDM activity values shown in Appendix 3-A will equal the Net Energy Savings from the OPA 2006-2010 Final CDM Results for Thunder Bay Hydro assigned to the Residential, General Service < 50 kW and General Service > 50 to 999 kW classes. The tables below outlined the annual values used for the CDM activity variable by rate class. These values reflect the net energy savings from 2006 to 2010 programs and how these programs have persistent savings from 2007 to 2013. However, for the years 2011 to 2013, the Net Energy Savings from the OPA 2006-2010 Final CDM Results are adjusted to include final results from 2011 programs that contribute to the four year licensed CDM kWh targets of 47,380,000 assigned to Thunder Bay Hydro. The 2011 Final CDM results are based on the 2011 Results Report provided to Thunder Bay Hydro by the OPA on July 25, 2012. The 2011 verified results have been included in the CDM activity variable by rate class since these results have impacted the actual 2011 power purchases. The following tables outline by rate class the

adjustments made to the Net Energy Savings from the OPA 2006-2010 Final CDM Results to include the impact of the final results from 2011 CDM programs and the persistent impact of the 2011 programs into 2012 and 2013. In addition, Table 3-2.4, 3-2.5, 3-2.6, 3-2.7 and 3-2.8, provide the Net Energy Savings from the OPA 2006-2010 Final CDM Results for the years 2006 to 2013.

Table 3-2.4: 2011 Final Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact (All Classes)

Thunder Bay Hydro 4 Year 2011 to 2014 kWh target				
47,380,000				
2011	2012	2013	2014	Total
kWh savings from 2011 programs with presistent impact				
2,157,479	2,157,479	2,157,479	2,031,020	8,503,456
OPA 2010 Final Results - kWh				
2006	2007	2008	2009	
3,246,310	6,046,051	8,583,640	12,494,278	
2010	2011	2012	2013	
12,510,028	10,995,318	10,739,336	10,554,593	

Table 3-2.5: 2011 Final Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact (Residential)

2011	2012	2013	2014	Total
kWh savings from 2011 programs with presistent impact				
1,087,989	1,087,989	1,087,989	1,024,217	4,288,184
OPA 2010 Final Results - kWh				
2006	2007	2008	2009	
3,246,310	6,046,051	8,223,982	9,005,150	
2010	2011	2012	2013	
7,147,184	6,743,585	6,487,602	6,302,859	

Table 3-2.6: 2011 Final Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact (General Service < 50 kW)

2011	2012	2013	2014	Total
kWh savings from 2011 programs with presistent impact				
481,059	481,059	481,059	452,862	1,896,040
OPA 2010 Final Results - kWh				
2006	2007	2008	2009	
0	0	100,064	1,326,665	
2010	2011	2012	2013	
2,342,359	2,342,359	2,342,359	2,342,359	

Table 3-2.7: 2011 Final Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact (General Service > 50 to 999 kW)

2011	2012	2013	2014	Total
kWh savings from 2011 programs with presistent impact				
479,337	479,337	479,337	451,241	1,889,251
OPA 2010 Final Results - kWh				
2006	2007	2008	2009	
0	0	259,593	2,151,240	
2010	2011	2012	2013	
2,982,452	1,909,374	1,909,374	1,909,374	

Table 3-2.8: 2011 Final Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact (General Service > 1000 kW)

2011	2012	2013	2014	Total
kWh savings from 2011 programs with presistent impact				
109,094	109,094	109,094	102,700	429,982
OPA 2010 Final Results - kWh				
2006	2007	2008	2009	
0	0	0	11,224	
2010	2011	2012	2013	
38,032	0	0	0	

The information in tables 3-2.5 to 3-2.8 will add to the total system information provided in table 3-2.4. Table 3-2.8, has been provided for the General Service > 1000 kW class for completeness but this information is not used in the load forecast for this class. The load forecast for this class in not based on a regression analysis and there is no CDM activity variable used in the load forecast of this class.

For 2013 for the Residential class, the monthly values for the Residential CDM activity variable will total 7,390,848 kWh which includes 6,302,859 kWh from the OPA final results plus 1,087,989 kWh reflecting the persistence of 2011 programs into 2013.

For 2013 for the General Service < 50 kW class, the monthly values for the General Service < 50 kW CDM activity variable will total 2,823,418 kWh which includes 2,342,359 kWh from the OPA final results plus 481,059 kWh reflecting the persistence of 2011 programs into 2013.

For 2013 for the General Service > 50 to 999 kW class, the monthly values for the General Service > 50 to 999 kW CDM activity variable will total 2,388,711 kWh which includes 1,909,374 kWh from the OPA final results plus 479,337 kWh reflecting the persistence of 2011 programs into 2013.

The impact of 2012 and 2013 CDM programs has not been included in the CDM activity variables since they do not impact the actual billed amount used in the regression analysis. A discussion on how the load forecast is adjusted for 2012 and 2013 programs and how LRAM variance account values are determined by rate class is provided later on in this schedule.

The prediction formulas have the following statistical results as shown in Table 3-2.9:

Table 3-2.9: Statistcial Results

Statistic	Residential	General Service < 50 kW	General Service > 50 to 999 kW
R Square	95%	77%	94%
Adjusted R Square	95%	76%	94%
F Test	567.3	99.1	284.0
T-stats by Coefficient			
Heating Degree Days	43.5	17.5	39.8
Cooling Degree Days	4.7	3.6	7.8
Number of Days in Month	8.1	2.1	5.2
Spring Fall Flag	(4.7)	(3.2)	(4.8)
CDM Activity	(4.8)	(6.9)	(5.2)
Ontario Real GDP Monthly %			3.2
Number of Customers			3.5
Number of Peak Hours			2.5
Intercept	(0.7)	2.3	0.1

The annual results of the above prediction formula compared to the actual annual billed values from 2000 to 2011 are shown in Tables 3-2.10 – 3-2.12 below. In addition, the predicted Residential, General Service < 50 kW and General Service > 50 to 999 kW billed values are provided for 2012 and 2013. For 2012 and 2013 the values reflect a weather normalized forecast for the full year. In addition, values for 2013 are provided with a 10 year average and a 20 year trend assumption for weather normalization.

Table 3-2.10: Residential Billed

Year	Actual	Predicted	% Difference
Billed Energy (GWh)			
2000	347.9	352.6	1.3%
2001	350.1	350.3	0.0%
2002	358.4	355.5	(0.8%)
2003	362.1	355.2	(1.9%)
2004	356.2	356.3	0.0%
2005	356.0	354.5	(0.4%)
2006	345.4	344.4	(0.3%)
2007	347.7	345.8	(0.5%)
2008	350.0	348.0	(0.6%)
2009	345.1	343.9	(0.4%)
2010	336.0	337.9	0.6%
2011	337.6	343.8	1.8%
2012 Weather Normal		**344.2**	
2013 Weather Normal		**343.6**	
2013 Weather Normal - 10 year average		**344.3**	
2013 Weather Normal - 20 year trend		**344.2**	

Table 3-2.11: General Service < 50 kW Billed

Year	Actual	Predicted	% Difference
Billed Energy (GWh)			
2000	151.1	146.8	(2.9%)
2001	149.2	146.9	(1.5%)
2002	151.6	148.7	(1.9%)
2003	145.4	148.1	1.8%
2004	148.4	147.9	(0.3%)
2005	147.4	148.3	0.6%
2006	141.7	146.4	3.4%
2007	140.8	147.7	4.9%
2008	140.8	148.3	5.3%
2009	137.5	140.8	2.5%
2010	132.8	133.8	0.8%
2011	135.7	133.4	(1.7%)
2012 Weather Normal		**133.1**	
2013 Weather Normal		**132.9**	
2013 Weather Normal - 10 year average		**133.1**	
2013 Weather Normal - 20 year trend		**133.3**	

Table 3-2.12: General Service > 50 to 999 kW Billed

Year	Actual	Predicted	% Difference
Billed Energy (GWh)			
2000	285.2	290.2	1.7%
2001	286.8	290.6	1.3%
2002	295.7	295.7	0.0%
2003	301.0	296.3	(1.5%)
2004	289.8	294.9	1.8%
2005	302.1	296.9	(1.7%)
2006	299.2	294.7	(1.5%)
2007	299.0	298.9	(0.0%)
2008	297.5	300.6	1.0%
2009	290.8	290.5	(0.1%)
2010	285.0	283.7	(0.5%)
2011	288.4	291.2	1.0%
2012 Weather Normal		**291.2**	
2013 Weather Normal		**291.7**	
2013 Weather Normal - 10 year average		**292.2**	
2013 Weather Normal - 20 year trend		**292.5**	

The weather normalized amount for 2013 is determined by using 2013 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 February 1999 to December 2011. The 2013 weather normalized 10 year average value represents the average heating degree days and cooling degree days that occurred from January 2002 to December 2011. The 2013 weather normalized 20 year trend value reflects the trend in monthly heating degree days and cooling degree days that occurred from January 1992 to December 2011.

The weather normal average from February 1999 to December 2011 has been used in this Application for the purposes of determining a billed kWh load forecast which is used to design rates.

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 3-2.13.

Table 3-2.13: Historical Customer/Connection Data

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Number of Customers/Connections								
2000	43,694	4,464	490	18	0	93	427	49,186
2001	43,780	4,459	476	18	0	105	429	49,267
2002	43,923	4,430	482	18	12,637	87	430	62,007
2003	44,031	4,384	499	14	12,739	135	430	62,232
2004	44,154	4,416	467	19	12,769	140	431	62,395
2005	44,249	4,413	480	18	12,858	153	432	62,602
2006	44,345	4,315	493	18	12,962	164	428	62,724
2007	44,422	4,274	501	19	12,976	153	435	62,779
2008	44,570	4,258	507	19	13,135	150	457	63,096
2009	44,646	4,266	506	21	13,039	158	459	63,094
2010	44,766	4,307	507	20	13,170	167	469	63,405
2011	44,931	4,341	506	19	13,091	148	470	63,505

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in Table 3-2.14. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2000 to 2011.

Table 3-2.14: Growth Rate in Customer/Connections

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads
Growth Rate in Customers/Connections							
2000							
2001	0.2%	(0.1%)	(2.8%)	0.0%		12.9%	0.5%
2002	0.3%	(0.6%)	1.4%	(2.3%)		(17.1%)	0.2%
2003	0.2%	(1.1%)	3.5%	(20.4%)	0.8%	55.2%	0.0%
2004	0.3%	0.7%	(6.4%)	32.1%	0.2%	3.7%	0.2%
2005	0.2%	(0.1%)	2.7%	(5.0%)	0.7%	9.3%	0.2%
2006	0.2%	(2.2%)	2.6%	2.4%	0.8%	7.2%	(0.9%)
2007	0.2%	(0.9%)	1.6%	3.7%	0.1%	(6.7%)	1.6%
2008	0.3%	(0.4%)	1.3%	1.8%	1.2%	(2.1%)	5.1%
2009	0.2%	0.2%	(0.2%)	11.0%	(0.7%)	5.4%	0.3%
2010	0.3%	1.0%	0.1%	(5.5%)	1.0%	5.6%	2.3%
2011	0.4%	0.8%	(0.2%)	(5.0%)	(0.6%)	(11.5%)	0.2%
Geometric Mean	**0.3%**	**(0.1%)**	**0.2%**	**3.8%**	**0.3%**	**1.1%**	**1.1%**

Except for the General Service > 1000 kW, the resulting geometric mean was first applied to the 2011 customer/connection numbers to determine the forecast of customer/connections in 2012. Then the geometric mean was applied again to the 2012 value to determine the 2013 forecast. For the General Service > 1000 kW class, the number of customers is held constant at the 2011 level since Thunder Bay Hydro does expect growth in number of customers for this class. Table 3-2.15 outlines the forecast of customers and connections by rate class.

Table 3-2.15: Customer/Connection Forecast

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Forecast Number of Customers/Connections								
2012	45,044	4,335	507	19	13,135	149	475	**63,665**
2013	45,158	4,330	507	19	13,180	151	481	**63,827**

Billed kWh Load Forecast – Non-Weather Sensitive Classes

For the purposes of this load forecast the non-weather sensitive classes include General Service > 1000 kW, Streetlights, Sentinel Lights and Unmetered Load. The first step in determining the load forecast for these classes is to review the historical customer/connection usage and use the historical data to forecast usage per customer. Table 3-2.16 provides the average annual usage per customer for the non-weather sensitive rate classes from 2000 to 2011.

Table 3-2.16: Historical Annual Usage per Customer

Year	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads
Annual kWh Usage Per Customer/Connection				
2000	9,007,215		821	
2001	8,784,152		821	
2002	8,661,377		821	
2003	12,270,998	843	821	3,842
2004	9,931,234	854	821	3,861
2005	12,177,309	845	821	3,947
2006	13,408,370	761	821	4,337
2007	12,370,795	841	821	4,635
2008	10,762,728	825	821	4,228
2009	9,001,536	889	821	4,267
2010	8,901,281	854	821	4,146
2011	9,683,426	855	821	4,173

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 3-2.17. The geometric mean growth rate has also been shown.

Table 3-2.17: Growth Rate in Usage Per Customer/Connection

Year	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads
Growth Rate in Customer/Connection				
2000				
2001	(2.5%)		0.0%	
2002	(1.4%)		0.0%	
2003	41.7%		0.0%	
2004	(19.1%)	1.2%	0.0%	0.5%
2005	22.6%	(1.0%)	0.0%	2.2%
2006	10.1%	(10.0%)	0.0%	9.9%
2007	(7.7%)	10.5%	0.0%	6.9%
2008	(13.0%)	(1.9%)	0.0%	(8.8%)
2009	(16.4%)	7.8%	0.0%	0.9%
2010	(1.1%)	(4.0%)	0.0%	(2.8%)
2011	8.8%	0.2%	0.0%	0.7%
Geometric Mean	**0.7%**	**0.2%**	**0.0%**	**1.0%**

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2011 usage to determine the 2012 forecast usage and then again to the 2012 value to determine the 2013 forecast. The resulting usage forecast as shown in Table 3-2.18 is as follows:

Table 3-2.18: Forecast Annual kWh Usage per Customer/Connection

Year	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads
Forecast Annual kWh Usage per Customers/Connection				
2012	9,747,361	857	821	4,216
2013	9,811,719	858	821	4,260

With the preceding information the billed energy forecast can be determined for non-weather sensitive classes by applying the forecast numbers of customers/connections from Table 3-2.16 by the forecast of annual usage per customer/connection from Table 3-2.18. The resulting billed energy forecast is shown in Table 3-2.19 below.

Table 3-2.19: Billed Energy Forecast

Year	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Billed Energy Forecast (GWh)					
2012	184.4	11.3	0.1	2.0	197.8
2013	185.6	11.3	0.1	2.0	199.1

With the completion of the above table the billed energy forecast for all rate classes has been determined and is provided in Table 3-2.20 which is a combination of information from Tables 3-2.10, 3-2.11, 3-2.12 and 3-2.19.

Table 3-2.20: Billed Energy Forecast (All Classes)

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Billed Energy Forecast (GWh)								
2012	**344.2**	**133.1**	**291.2**	**184.4**	**11.3**	**0.1**	**2.0**	**966.2**
2013	**343.6**	**132.9**	**291.7**	**185.6**	**11.3**	**0.1**	**2.0**	**967.2**

In the next step a manual adjustment is made to reflect the impact of 2012 and 2013 CDM programs on the load forecast. This adjustment reflects the “gross” impact of 2012 and 2013 CDM programs on the load forecast. The gross impact includes the net results measured by the OPA plus an estimate of the average net to gross adjustment reflecting gross and net savings information provided in the OPA 2006-2010 Final CDM Results. The net results provide a measurement of the program effectiveness used to achieve the LDC’s targets. The gross results include the net results plus the estimated impact of customers participating in a program even if an incentive was not provided to participate. In the past this has been termed the level of “free ridership”. In other words, the gross results include the results from those who participated in the program because there was an incentive plus those who participated even if there was not an incentive. In Thunder Bay Hydro’s view it is the gross level that impacts the load forecast.

Table 3-2.21 outlines the average net to gross factor of 65.4% based on information provided in the OPA 2006-2010 Final CDM Results for Thunder Bay Hydro (Appendix 3-A)

Table 3-2.21: Average Net to Gross Percentage

	OPA 2006-2010 Final CDM Results (Gross)	OPA 2006-2010 Final CDM Results (Net)	# Difference	% Difference of Net
2006	3,625,491	3,246,310	379,181	11.7%
2007	12,821,744	6,046,051	6,775,693	112.1%
2008	13,497,193	8,583,640	4,913,553	57.2%
2009	19,428,898	12,494,278	6,934,620	55.5%
2010	20,258,011	12,510,028	7,747,983	61.9%
2011	18,761,204	10,995,318	7,765,886	70.6%
2012	18,159,424	10,739,336	7,420,088	69.1%
2013	17,798,355	10,554,593	7,243,762	68.6%
Total	124,350,320	75,169,554	49,180,766	65.4%

As previously discussed the 2011 preliminary actual savings from 2011 CDM programs are known and have been used in the CDM activity variable included in the regression analysis supporting the prediction formulas. However, the 2011 results will impact on the level saving needed from 2012 to 2014 programs in order to achieve the licensed 4 year CDM target. Based on the following table the 2011 verified savings will contribute 17.9% to the four year target. In Table 3-2.22 the 2011 results are consistent with the information provided in Table 3-2.4. The table indicates that assuming persistence, 2012 to 2014 programs will need to achieve 13.7% of the four year target each year in order to achieve the target.

Table 3-2.22: Schedule to Achieve 4 Year kWh CDM Target

4 Year 2011 to 2014 kWh target					
47,380,000					
	2011	2012	2013	2014	Total
2011 Programs	4.6%	4.6%	4.6%	4.3%	17.9%
2012 Programs		13.7%	13.7%	13.7%	41.0%
2013 Programs			13.7%	13.7%	27.4%
2014 Programs				13.7%	13.7%
	4.6%	18.2%	31.9%	45.3%	100.0%
kWh					
2011 Programs	2,157,479	2,157,479	2,157,479	2,031,020	8,503,456
2012 Programs		6,479,424	6,479,424	6,479,424	19,438,272
2013 Programs			6,479,424	6,479,424	12,958,848
2014 Programs				6,479,424	6,479,424
	2,157,479	8,636,903	15,116,327	21,469,292	47,380,000

The above table suggests that in 2012, the savings from 2012 will be 6,479,424 kWh on a net basis. However on a gross basis this amount would be 6,479,424 times 1.654 (i.e. the net to

gross factor determined in table 3-2.21) or 10,718,681 kWh. In Thunder Bay Hydro's view, the 2012 load forecast should be adjusted by 10,718,681 kWh to reflect CDM savings from 2012 programs. As discussed above in regards to the CDM Activity variables, the persistent savings from 2011 programs in 2012 have been reflected in the prediction formula for the Residential, General Service < 50 kW and General Service > 50 to 999 kW classes.

The above table also suggest that in 2013, the savings from 2012 and 2013 programs will be a 6,479,424 kWh times two or 12,958,848 kWh on a net basis. However on a gross basis this amount would be 12,958,848 times 1.654 (i.e. the net to gross factor determined in table 3-2.21) or 21,437,361 kWh. In Thunder Bay Hydro's view, the 2013 load forecast should be adjusted by 21,437,361 kWh to reflect CDM savings from 2012 and 2013 programs.

In accordance with the Board's Guidelines for Electricity Distributor Conservation and Demand Management [EB-2012-0003], issued April 26, 2012, it is Thunder Bay Hydro's understanding that as part of this application expected CDM savings in 2013 from 2011, 2012 and 2013 programs will need to be established for LRAM variance accounts purposes. It is also Thunder Bay 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 Thunder Bay Hydro's view that the units used for the 2013 LRAM variance account should also be on a net basis. Based on the net information in table 3-2.22, Thunder Bay Hydro expects to achieve 15,116,327 net kWh savings in 2013 from 2011 to 2013 CDM programs. For LRAM variance account purposes, Table 3-2.23 outlines how this expected savings has been allocated to rate class using the 2013 information from table 3-2.20. 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 3-2.26.

Table 3-2.23: 2013 Expected Savings for LRAM Variance Account

	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
kWh	5,369,511	2,076,931	4,558,323	2,900,856	176,764	1,936	32,005	15,116,327
kW where applicable			12,385	8,992	498	5		21,881

Table 3.2.24 outlines how the classes have been adjusted to adjust for CDM savings from 2012 and 2013 programs.

Table 3-2.24: Adjustment for CDM

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Unmetered Loads	Total
Billed Energy Forecast (GWh)								
2012	344.2	133.1	291.2	184.4	11.25	0.1	2.0	966.2
2013	343.6	132.9	291.7	185.6	11.31	0.1	2.0	967.2
CDM Adjustment (GWh)								
2012	(3.8)	(1.5)	(3.2)	(2.0)	(0.1)	(0.0)	(0.0)	(10.7)
2013	(7.6)	(2.9)	(6.5)	(4.1)	(0.3)	(0.0)	(0.0)	(21.4)
CDM Adjusted Billed Energy Forecast (GWh)								
2012	340.3	131.6	288.0	182.3	11.13	0.1	2.0	955.5
2013	335.9	129.9	285.2	181.5	11.06	0.1	2.0	945.7

Billed KW Load Forecast

There are four rate classes shown in Table 3-2.24 that charge volumetric distribution on per kW basis. 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.

Table 3-2.25 outlines the annual demand units by applicable rate class.

Table 3-2.25: Historical Annual kW per Applicable Rate Class

Year	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Total
Billed Annual kW					
2000	795,748	512,782	0	212	1,308,742
2001	790,838	518,129	0	239	1,309,207
2002	845,849	637,635	30,540	198	1,514,223
2003	816,067	518,246	30,275	308	1,364,896
2004	780,982	548,206	30,427	319	1,359,934
2005	845,849	637,635	30,540	349	1,514,373
2006	845,006	705,022	30,657	374	1,581,059
2007	793,506	705,087	30,889	349	1,529,832
2008	785,846	588,629	31,467	342	1,406,283
2009	770,046	550,678	30,981	360	1,352,064
2010	757,535	530,686	28,911	380	1,317,511
2011	739,886	521,083	31,832	336	1,293,137

Table 3-2.26 illustrates the historical ratio of kW/kWh as well as the average ratio for 2000 to 2011.

Table 3-2.26: Historical kW/KWh Ratio per Applicable Rate Class

Year	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights
Ratio of kW to kWh				
2000	0.2790%	0.3163%		0.2778%
2001	0.2757%	0.3277%		0.2778%
2002	0.2861%	0.4187%		0.2778%
2003	0.2711%	0.3017%	0.2818%	0.2778%
2004	0.2695%	0.2984%	0.2791%	0.2778%
2005	0.2800%	0.2978%	0.2810%	0.2778%
2006	0.2824%	0.2921%	0.3108%	0.2778%
2007	0.2654%	0.3053%	0.2832%	0.2778%
2008	0.2641%	0.2878%	0.2904%	0.2778%
2009	0.2648%	0.2902%	0.2673%	0.2778%
2010	0.2658%	0.2993%	0.2572%	0.2778%
2011	0.2566%	0.2845%	0.2844%	0.2778%
Average 2000 to 2011	**0.2717%**	**0.3100%**	**0.2817%**	**0.2778%**

The average ratio was applied to the billed energy forecast in Table 3-2.24 to provide the forecast of kW by rate class as shown below. Table 3-2.27 outlines the forecast of kW for the applicable rate classes.

Table 3-2.27: kW Forecast by Applicable Rate Class

Year	General Service > 50 to 999 kW	General Service > 1000 kW	Streetlights	Sentinel Lights	Total
Predicted Billed kW					
2012	**782,499**	**565,225**	**31,343**	**336**	**1,379,404**
2013	**774,872**	**562,588**	**31,152**	**336**	**1,368,948**

Table 3-3.28 provides a summary of the billing determinants by rate class that is used to develop the proposed rates.

Table 3-2.28: Summary of Forecast

	2009 Board Approved	2009	2010	2011	2012 Weather Normalized Bridge	2013 Weather Normalized Test
BILLING DETERMINANTS BY CLASS						
Residential						
Customers	44,635	44,646	44,766	44,931	45,044	45,158
kWh	350,217,935	345,140,283	336,026,363	337,606,103	340,342,141	335,941,782
General Service < 50 kW						
Customers	4,466	4,266	4,307	4,341	4,335	4,330
kWh	144,258,193	137,462,603	132,778,549	135,729,832	131,576,021	129,942,565
General Service > 50 to 999 kW						
Customers	511	506	507	506	507	507
kWh	305,337,414	290,786,510	285,044,355	288,359,056	287,997,314	285,190,036
kW	718,710	770,046	757,535	739,886	782,499	774,872
General Service ≥ 1000 kW						
Connections	19	21	20	19	19	19
kWh	194,477,088	189,782,376	177,283,842	183,178,133	182,342,067	181,491,144
kW	561,149	550,678	530,686	521,083	565,225	562,588
Street Lighting						
Connections	13,091	13,039	13,170	13,091	13,135	13,180
kWh	10,616,947	11,591,322	11,241,250	11,194,474	11,127,205	11,059,201
kW	31,276	30,981	28,911	31,832	31,343	31,152
Sentinel Lights						
Connections	176	158	167	148	149	151
kWh	146,789	129,618	136,868	121,136	121,134	121,120
kW	402	360	380	336	336	336
Unmetered Loads						
Customers	437	459	469	470	475	481
kWh	1,786,004	1,956,360	1,945,317	1,961,690	1,982,032	2,002,380
Total						
Customer/Connections	63,335	63,094	63,405	63,505	63,665	63,827
kWh	1,006,840,371	976,849,071	944,456,544	958,150,425	955,487,915	945,748,229
kW from applicable classes	1,311,538	1,352,064	1,317,511	1,293,137	1,379,404	1,368,948

OPERATING REVENUE VARIANCE ANALYSIS

THROUGHPUT REVENUE and OTHER OPERATING REVENUE

Variance Analysis on Throughput Revenue

Table 3-3.1 below provides a summary and variances for throughput and other operating revenues from 2009 to 2013 with a discussion of the year-over-year variances following the table.

Table 3-3.1-Summary of Operating Revenue

	2009 Board Approved	2009 Actual	Difference $	2010 Actual	Difference $	2011 Actual	Difference $	2012 Bridge (CGAAP)	Difference $	2013 Test (CGAAP)	Difference $	2013 Test (MCGAAP)	Difference $
Distribution Revenue													
Residential	$ 10,502,976	$ 10,589,372	$ 86,395	$ 9,818,871	$ (770,500)	$ 9,979,362	$ 160,491	$ 13,605,263	$ 3,625,901	$11,408,885	$ (2,196,378)	$ 11,408,885	$ (2,196,378)
GS<50	$ 2,853,837	$ 2,663,568	$ (190,269)	$ 2,621,638	$ (41,930)	$ 2,785,326	$ 163,688	$ 3,250,844	$ 465,518	$ 3,224,349	$ (26,495)	$ 3,224,349	$ (26,495)
GS 50 to 999 kW	$ 2,141,592	$ 2,084,513	$ (57,078)	$ 2,316,575	$ 232,062	$ 2,448,406	$ 131,831	$ 2,368,052	$ (80,354)	$ 3,202,670	$ 834,618	$ 3,202,670	$ 834,618
GS > 1,000 kW	$ 1,089,278	$ 1,007,832	$ (81,446)	$ 1,134,073	$ 126,241	$ 1,308,383	$ 174,310	$ 1,422,949	$ 114,566	$ 1,589,025	$ 166,077	$ 1,589,025	$ 166,077
Street Lighting	$ 432,470	$ 299,269	$ (133,201)	$ 498,050	$ 198,781	$ 733,883	$ 235,833	$ 744,855	$ 10,973	$ 400,628	$ (344,227)	$ 400,628	$ (344,227)
Sentinel Lights	$ 15,679	$ -	$ (15,679)	$ 15,922	$ 15,922	$ 13,057	$ (2,866)	$ 14,188	$ 1,131	$ 14,450	$ 262	$ 14,450	$ 262
Unmetered Scattered Load	$ 70,125	$ 134,844	$ 64,719	$ 98,936	$ (35,909)	$ 126,649	$ 27,713	$ 109,101	$ (17,548)	$ 61,047	$ (48,054)	$ 61,047	$ (48,054)
Total	**$ 17,105,956**	**$ 16,779,398**	**$ (326,559)**	**$ 16,504,064**	**$ (275,333)**	**$ 17,395,065**	**$ 891,001**	**$ 21,515,252**	**$ 4,120,187**	$19,901,055	$ (1,614,197)	**$ 19,901,055**	**$ (1,614,197)**
% of Total Revenue	**92%**	**92%**	**(2%)**	**89%**	**(2%)**	**87%**	**5%**	**93%**	**24%**	**92%**	**(8%)**	**92%**	**(8%)**
Other Operating Revenues													
Specific Service Charges	$ 308,700	$ 320,631	$ 11,931	$ 322,428	$ 1,797	$ 270,471	$ (51,958)	$ 274,216	$ 3,745	$ 267,807	$ (6,409)	$ 267,807	$ (6,409)
Late Payment Charges	$ 282,000	$ 289,447	$ 7,447	$ 261,868	$ (27,579)	$ 297,478	$ 35,610	$ 297,000	$ (478)	$ 297,000	$ -	$ 297,000	$ -
SSS Revenue	$ 131,500	$ 128,694	$ (2,806)	$ 127,920	$ (774)	$ 131,704	$ 3,784	$ 131,340	$ (364)	$ 131,340	$ -	$ 131,340	$ -
RS Rev	$ 71,800	$ 75,266	$ 3,466	$ 66,688	$ (8,578)	$ 55,954	$ (10,734)	$ 59,150	$ 3,196	$ 59,150	$ -	$ 59,150	$ -
Serv Tx Requests	$ 3,400	$ 1,681	$ (1,720)	$ 5,629	$ 3,948	$ 1,786	$ (3,843)	$ 1,900	$ 115	$ 1,900	$ -	$ 1,900	$ -
Rent from Electric Property	$ 436,300	$ 460,835	$ 24,535	$ 462,179	$ 1,344	$ 477,108	$ 14,929	$ 471,000	$ (6,108)	$ 471,000	$ -	$ 471,000	$ -
Other Utility Operating Income		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Electric Revenues	$ 2,710	$ 93,337	$ 90,627	$ 139,302	$ 45,965	$ 202,431	$ 63,128	$ 168,726	$ (33,705)	$ 180,818	$ 12,092	$ 180,818	$ 12,092
Provision for Rate Refunds		$ (361,129)	$ (361,129)	$ -	$ 361,129	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Government Assistance Directly Credited to Income		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,712	$ 12,712
SPC Recovery		$ -	$ -	$ 224,891	$ 224,891	$ 164,329	$ (60,562)	$ -	$ (164,329)	$ -	$ -	$ -	$ -
Gain on Disposition of Utility and Other Property		$ 14,336	$ 14,336	$ 400	$ (13,936)	$ 26,513	$ 26,113	$ (12,200)	$ (38,713)	$ 49,850	$ 62,050	$ (14,120)	$ (1,920)
Loss from Retirement of Utility and Other Property		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (30,000)	$ (30,000)	$ (30,000)	$ (30,000)
Revenues from Non-Utility Operations	$ (18,114)	$ 680,002	$ 698,116	$ 656,246	$ (23,756)	$ 739,783	$ 83,537	$ 879,343	$ 139,560	$ 668,839	$ (210,504)	$ 668,839	$ (210,504)
Expenses of Non-Utility Operations		$ (646,324)	$ (646,324)	$ (658,682)	$ (12,358)	$ (739,003)	$ (80,321)	$ (890,954)	$ (151,951)	$ (677,224)	$ 213,730	$ (677,101)	$ 213,853
Miscellaneous Non-Operating Income	$ 124,494	$ 182,056	$ 57,562	$ 251,896	$ 69,840	$ 277,307	$ 25,411	$ 278,000	$ 693	$ 272,000	$ (6,000)	$ 272,000	$ (6,000)
Foreign Exchange Gains and Losses, Including Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest and Dividend Income	$ 130,000	$ 159,335	$ 29,335	$ 178,369	$ 19,034	$ 747,158	$ 568,789	$ (99,807)	$ (846,965)	$ 110,390	$ 210,197	$ 110,390	$ 210,197
Total	**$ 1,497,790**	**$ 1,398,167**	**$ (99,623)**	**$ 2,039,134**	**$ 640,967**	**$ 2,653,018**	**$ 613,883**	**$ 1,557,714**	**$ (1,095,304)**	**$ 1,802,870**	**$ 245,156**	**$ 1,751,736**	$ 194,022
% of Total Revenue	**8%**	**8%**		**11%**		**13%**		**7%**		**8%**		**8%**	
Grand Total	**$ 18,603,746**	**$ 18,177,565**	**$ (426,181)**	**$ 18,543,198**	**$ 365,633**	**$ 20,048,083**	**$ 1,504,884**	**$ 23,072,966**	**$ 3,024,883**	**$ 21,703,925**	**$ (1,369,041)**	**$ 21,652,791**	**$ (1,420,176)**

Table 3-3.2, below shows the distribution revenue for the 2013 Test Year at both the existing and proposed rates:

Table 3-3.2

	Revenue for 2013 Test Year	
Class	**Existing Rates**	**Proposed Rates**
Residential	$10,514,949	$11,408,885
GS < 50 kW	$2,971,708	$3,224,349
GS >50 to 999 kW	$2,455,695	$3,202,670
GS >1000 to 4999 kW	$1,560,123	$1,589,025
Large Use	$0	$0
Sentinel Lights	$13,317	$14,450
Street Lighting	$748,504	$400,628
Unmetered and Scattered	$77,425	$61,047

2009 Board Approved

Thunder Bay Hydro's operating revenue in fiscal 2009 was $18,603,746. Throughput revenue was $17,105,956 or 92% of total revenues. Other net operating revenue, accounts for the remaining $1,497,790.

2009 Actual

Thunder Bay Hydro's operating revenue in fiscal 2009 was $18,177,565. Throughput revenue was $16,779,398 or 92% of total revenues as shown in Table 3-3.3. Other net operating revenue, accounts for the remaining $1,398,167.

Table 3-3.3: Summary of Operating Revenue

Distribution Revenue	2009 Board Approved	2009 Actual	Variance	% Variance
Residential	$ 10,502,976	$ 10,589,372	$ 86,395	0.82%
GS<50	$ 2,853,837	$ 2,663,568	$ (190,269)	(6.7%)
GS 50 to 999 kW	$ 2,141,592	$ 2,084,513	$ (57,078)	(2.7%)
GS > 1,000 kW	$ 1,089,278	$ 1,007,832	$ (81,446)	(7.5%)
Street Lighting	$ 432,470	$ 299,269	$ (133,201)	(30.8%)
Sentinel Lights	$ 15,679	$ -	$ (15,679)	(100.0%)
Unmetered Scattered Load	$ 70,125	$ 134,844	$ 64,719	92.3%
Total	**$ 17,105,956**	**$ 16,779,398**	**$ (326,559)**	
% of Total Revenue	**92%**	**92%**	(1.9%)	

Throughput revenue for 2009 was 1.9% or $326,559 lower than the amounts approved in the 2009 Cost of Service application primarily due to lower kWh usage in the majority of rate classes.

The timing difference between the 2009 Actual amounts which are based on the fiscal year of January 1 to December 31, 2009, and the 2009 EDR amounts, which are based on the rate year of May 1, 2009 to April 30, 2010 also contribute to the variance, since the 2009 rates did not come into effect until May 2009.

Table 3-3.4 below compares the 2009 EDR Approved billing quantities to the 2009 Actual quantities.

Table 3-3.4: Comparison 2009 Actual to 2009 Board Approved

	Customers/Connections			kWh			kW		
Rate Class	2009 OEB Approved	2009 Actual	Variance	2009 OEB Approved	2009 Actual	Variance	2009 OEB Approved	2009 Actual	Variance
Residential	44,635	44,646	11	350,217,935	348,392,935	(1,825,000)			-
GS < 50 kW	4,466	4,266	(200)	144,258,193	138,834,577	(5,423,617)			-
GS > 50 kW	511	506	(5)	305,337,414	293,502,765	(11,834,648)	718,710	770,046	51,335
GS > 1000 kW	19	21	2	194,477,088	188,304,355	(6,172,733)	561,149	550,678	(10,471)
Street Lights	13,091	13,039	(53)	10,616,947	11,577,185	960,238	31,276	30,981	(295)
Sentinel Lights	176	158	(18)	146,789	129,618	(17,171)	402	360	(42)
Unmetered Scattered Load	437	459	21	1,786,004	1,995,125	209,121			-
TOTAL	63,335	63,094	(241)	1,006,840,371	982,736,561	(24,103,810)	1,311,538	1,352,064	40,527

2010 Actual

Thunder Bay Hydro's operating revenue in fiscal 2010 was $18,543,198. Throughput revenue totaled $16,504,064 or 89% of total revenues as shown below in Table 3-3.5. Other net operating revenue, accounts for the remaining balance of $2,039,134.

Comparison 2010 Actual to 2009 Actual – Throughput Revenue

Table 3-3.5: Summary of Operating Revenue

Distribution Revene	2009 Actual	2010 Actual	Difference $	% Variance
Residential	$ 10,589,372	$ 9,818,871	$ (770,500)	(7.3%)
GS<50	$ 2,663,568	$ 2,621,638	$ (41,930)	(1.6%)
GS 50 to 999 kW	$ 2,084,513	$ 2,316,575	$ 232,062	11.1%
GS > 1,000 kW	$ 1,007,832	$ 1,134,073	$ 126,241	12.5%
Street Lighting	$ 299,269	$ 498,050	$ 198,781	66.4%
Sentinel Lights	$ -	$ 15,922	$ 15,922	
Unmetered Scattered Load	$ 134,844	$ 98,936	$ (35,909)	(26.6%)
Total	**$ 16,779,398**	**$ 16,504,064**	**$ (275,333)**	
% of Total Revenue	**92.31%**	**87.94%**	**(1.6%)**	

The 2010 throughput revenue was $275,333 or 1.6% lower than the 2009 actual revenue due to an overall decrease in usage and load for the majority of rate classes, despite a modest overall rate increase of 0.18%. Notwithstanding load reductions for the general service > 50 kW and > 1,000 kW and the Street Lighting classes, revenue increased due to rate increases and adjustments to revenue-cost ratios as approved in Thunder Bay Hydro's 2009 EDR decision in EB-2008-0245 to get these rate classes to the lower limit of the Board Policy range.

Table 3-3.6 below compares the 2009 Actual billing quantities to the 2010 Actual quantities.

Table 3-3.6: Comparison 2010 Actual to 2009 Actuals

	Customers/Connections			kWh			kW		
Rate Class	2009 Actual	2010 Actual	Variance	2009 Actual	2010 Actual	Variance	2009 Actual	2010 Actual	Variance
Residential	44,646	44,766	120	348,392,935	335,642,652	(12,750,283)			-
GS < 50 kW	4,266	4,307	41	138,834,577	132,888,997	(5,945,580)			-
GS > 50 kW	506	507	1	293,502,765	285,923,734	(7,579,031)	770,046	757,535	(12,511)
GS > 1000 kW	21	20	(1)	188,304,355	176,362,624	(11,941,732)	550,678	530,686	(19,992)
Street Lights	13,039	13,170	131	11,577,185	11,205,554	(371,631)	30,981	28,911	(2,070)
Sentinel Lights	158	167	9	129,618	136,868	7,250	360	380	20
Unmetered Scattered Load	459	469	11	1,995,125	1,952,259	(42,866)			-
TOTAL	63,094	63,405	311	982,736,561	944,112,687	(38,623,874)	1,352,064	1,317,511	(34,553)

2011 Actual*:*

Thunder Bay Hydro's operating revenue in fiscal 2011 was $20,048,083. Throughput revenue totaled $17,395,065 or 87% of total revenues as shown below in Table 3-3.7. Other net operating revenue, accounts for the remaining revenue of $2,653,018.

Comparison 2011 Actual to 2010 Actual Throughput Revenue

Table 3-3.7: Summary of Operating Revenue

Distribution Revene	2010 Actual	2011 Actual	Difference $	% Variance
Residential	$ 9,818,871	$ 9,979,362	$ 160,491	1.6%
GS<50	$ 2,621,638	$ 2,785,326	$ 163,688	6.2%
GS 50 to 999 kW	$ 2,316,575	$ 2,448,406	$ 131,831	5.7%
GS > 1,000 kW	$ 1,134,073	$ 1,308,383	$ 174,310	15.4%
Street Lighting	$ 498,050	$ 733,883	$ 235,833	47.4%
Sentinel Lights	$ 15,922	$ 13,057	$ (2,866)	(18.0%)
Unmetered Scattered Load	$ 98,936	$ 126,649	$ 27,713	28.0%
Total	**$ 16,504,064**	**$ 17,395,065**	**$ 891,001**	
% of Total Revenue	**88%**	**86%**	**5.4%**	

Throughput revenue in 2011 was 5.4% or $891,001 higher than in 2010 due to a combination of a one-time recognition of throughput revenue for disposition of OEB account 1562 in the amount of $764,217, the 2011 IRM rate increase of 0.18% effective May 1, 2011 and an increase in overall usage. Removing the impact of account 1562 PILs disposition, the increase is 0.77% or $126,784. In addition, the annual Heating Degree Days were 9.5% higher in 2011 compared to 2010, and thus, contributed to the overall increase in usage.

Table 3-3.8 below compares the 2010 Actual billing quantities to the 2011 Actual quantities.

Table 3-3.8: Comparison 2011 Actual to 2010 Actuals

	Customers/Connections			kWh			kW		
Rate Class	2010 Actual	2011 Actual	Variance	2010 Actual	2011 Actual	Variance	2010 Actual	2011 Actual	Variance
Residential	44,766	44,931	165	335,642,652	337,828,769	2,186,117			-
GS < 50 kW	4,307	4,341	34	132,888,997	135,512,614	2,623,617			-
GS > 50 kW	507	506	(1)	285,923,734	287,676,650	1,752,916	757,535	739,886	(17,649)
GS > 1000 kW	20	19	(1)	176,362,624	182,011,908	5,649,285	530,686	521,083	(9,602)
Street Lights	13,170	13,091	(79)	11,205,554	11,244,633	39,080	28,911	31,832	2,921
Sentinel Lights	167	148	(19)	136,868	121,136	(15,732)	380	336	(44)
Unmetered Scattered Load	469	470	1	1,952,259	1,965,492	13,233			-
TOTAL	63,405	63,505	100	944,112,687	956,361,203	12,248,516	1,317,511	1,293,137	(24,374)

2012 Bridge Year

Thunder Bay Hydro's operating revenue is forecast to be $23,072,966. Throughput revenue totals $21,515,252 or 93% of total revenues as shown below in Table 3-3.9. Other net operating revenue, accounts for the remaining revenue of $1,557,714.

Comparison 2012 Bridge to 2011 Forecast Throughput Revenue

Table 3-3.9: Summary of Operating Revenue

Distribution Revene	2011 Forecasted	2012 Bridge (CGAAP)	Difference $	% Variance
Residential	$ 9,979,362	$ 13,605,263	$ 3,625,901	36.3%
GS<50	$ 2,785,326	$ 3,250,844	$ 465,518	16.7%
GS 50 to 999 kW	$ 2,448,406	$ 2,368,052	$ (80,354)	(3.3%)
GS > 1,000 kW	$ 1,308,383	$ 1,422,949	$ 114,566	8.8%
Street Lighting	$ 733,883	$ 744,855	$ 10,973	1.5%
Sentinel Lights	$ 13,057	$ 14,188	$ 1,131	8.7%
Unmetered Scattered Load	$ 126,649	$ 109,101	$ (17,548)	(13.9%)
Total	**$ 17,395,065**	**$ 21,515,252**	**$ 4,120,187**	
% of Total Revenue	**86%**	**93%**	**23.7%**	

Total throughput revenue is forecast to be 23.7% or $4,120,187 higher than the 2011 amounts. Of this amount $4,224,606 is related to the Smart Meter disposal as at December 31, 2011 (Smart Meter rate adder from 2006 to April 2012; plus 2012 Smart Meter Incremental Revenue Requirement is all recognized in 2012). Removing $764,217 from the 2011 throughput revenue caused by the one-time PILs disposition and the $4,224,606 from the 2012 throughput revenue being the impact of the Smart Meter disposition, the throughput operating revenue actually declined by 1.02% or $170,502. The variance in the load can be seen in the Table 3-3.10 below.

Table 3-3.10: Comparison 2012 Bridge to 2011 Actuals

	Customers/Connections			kWh			kW		
Rate Class	2011 Actual	2012 Forecasted	Variance	2011 Actual	2012 Forecasted	Variance	2011 Actual	2012 Forecasted	Variance
Residential	44,931	45,044	114	337,828,769	340,342,141	2,513,373			-
GS < 50 kW	4,341	4,335	(5)	135,512,614	131,576,021	(3,936,593)			-
GS > 50 kW	506	507	1	287,676,650	287,997,314	320,664	739,886	782,499	42,614
GS > 1000 kW	19	19	-	182,011,908	182,342,067	330,159	521,083	565,225	44,142
Street Lights	13,091	13,135	45	11,244,633	11,127,205	(117,429)	31,832	31,343	(489)
Sentinel Lights	148	149	2	121,136	121,134	(2)	336	336	(0)
Unmetered Scattered Load	470	475	5	1,965,492	1,982,032	16,540			-
TOTAL	63,505	63,665	161	956,361,203	955,487,915	(873,288)	1,293,137	1,379,404	86,268

2013 Test Year (MCGAAP)

Thunder Bay Hydro's 2013 Test Year operating revenue is forecast to be $21,652,791. Throughput revenue totals $19,901,055 or 92% of total revenues. Other operating revenue,

accounts for the remaining revenue of $1,751,736. The revenues in Table 3-3.11 are all at proposed rates.

Comparison of 2013 Test Year to 2012 Bridge Year Throughput Revenue

Table 3-3.11: Summary of Operating Revenue

Distribution Revene	2012 Bridge (CGAAP)	2013 Test (MCGAAP)	Difference $	% Variance
Residential	$ 13,605,263	$ 11,408,885	$ (2,196,378)	(16.1%)
GS<50	$ 3,250,844	$ 3,224,349	$ (26,495)	(0.8%)
GS 50 to 999 kW	$ 2,368,052	$ 3,202,670	$ 834,618	35.2%
GS > 1,000 kW	$ 1,422,949	$ 1,589,025	$ 166,077	11.7%
Street Lighting	$ 744,855	$ 400,628	$ (344,227)	(46.2%)
Sentinel Lights	$ 14,188	$ 14,450	$ 262	1.8%
Unmetered Scattered Load	$ 109,101	$ 61,047	$ (48,054)	(44.0%)
Total	**$ 21,515,252**	**$ 19,901,055**	**$ (1,614,197)**	
% of Total Revenue	**93.249%**	**91.910%**	**(7.5%)**	

Total throughput revenue is forecast to be 7.5% lower, or $1,614,197 than the 2012 Bridge year. Of this amount $3,958,967 is related to the Smart Meter disposal as at December 31, 2011 (life to date Smart Meter incremental revenue requirement is 100% recognized in 2012). Excluding the impact of the life-to-date Smart Meter revenue, the actual throughput revenue increased by 13.4%, or $2,344,770.

Table 3-3.12 below compares the 2012 Bridge Year billing quantities to the 2013 Test Year billing quantities.

Table 3-3.12: Comparison 2013 Test Year to 2012 Actuals

	Customers/Connections			kWh			kW		
Rate Class	2012 Forecasted	2013 Forecasted	Variance	2012 Forecasted	2013 Forecasted	Variance	2012 Forecasted	2013 Forecasted	Variance
Residential	45,044	45,158	114	340,342,141	335,941,782	(4,400,360)			-
GS < 50 kW	4,335	4,330	(5)	131,576,021	129,942,565	(1,633,456)			-
GS > 50 kW	507	507	1	287,997,314	285,190,036	(2,807,278)	782,499	774,872	(7,627)
GS > 1000 kW	19	19	-	182,342,067	181,491,144	(850,923)	565,225	562,588	(2,638)
Street Lights	13,135	13,180	45	11,127,205	11,059,201	(68,003)	31,343	31,152	(192)
Sentinel Lights	149	151	2	121,134	121,120	(14)	336	336	(0)
Unmetered Scattered Load	475	481	5	1,982,032	2,002,380	20,348			-
TOTAL	63,665	63,827	161	955,487,915	945,748,229	(9,739,687)	1,379,404	1,368,948	(10,457)

TRANSFORMER ALLOWANCE

Thunder Bay Hydro currently provides a Transformer Ownership Allowance Credit of $0.60/kW to those customers that own their own transformer facilities. Thunder Bay Hydro is proposing to maintain this rate for the 2013 Test Year for eligible customers.

VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28 2012, Thunder Bay Hydro has provided variance analyses in Table 3-3.13 below for each USoA account and provided explanations for variances exceeding a materiality threshold of $85,000.

Table 3-3.13: Summary of Other Distribution Revenue

Other Operating Revenues	2009 Board Approved	2009 Actual	Difference $	2010 Actual	Difference $	2011 Actual	Difference $	2012 Bridge (CGAAP)	Difference $	2013 Test (CGAAP)	Difference $	2013 Test (MCGAAP)	Difference $
Specific Service Charges	$ 308,700	$ 320,631	$ 11,931	$ 322,428	$ 1,797	$ 270,471	$ (51,958)	$ 274,216	$ 3,745	$ 267,807	$ (6,409)	$ 267,807	$ (6,409)
Late Payment Charges	$ 282,000	$ 289,447	$ 7,447	$ 261,868	$ (27,579)	$ 297,478	$ 35,610	$ 297,000	$ (478)	$ 297,000	$ -	$ 297,000	$ -
SSS Revenue	$ 131,500	$ 128,694	$ (2,806)	$ 127,920	$ (774)	$ 131,704	$ 3,784	$ 131,340	$ (364)	$ 131,340	$ -	$ 131,340	$ -
RS Rev	$ 71,800	$ 75,266	$ 3,466	$ 66,688	$ (8,578)	$ 55,954	$ (10,734)	$ 59,150	$ 3,196	$ 59,150	$ -	$ 59,150	$ -
Serv Tx Requests	$ 3,400	$ 1,681	$ (1,720)	$ 5,629	$ 3,948	$ 1,786	$ (3,843)	$ 1,900	$ 115	$ 1,900	$ -	$ 1,900	$ -
Rent from Electric Property	$ 436,300	$ 460,835	$ 24,535	$ 462,179	$ 1,344	$ 477,108	$ 14,929	$ 471,000	$ (6,108)	$ 471,000	$ -	$ 471,000	$ -
Other Utility Operating Income		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Electric Revenues	$ 2,710	$ 93,337	$ 90,627	$ 139,302	$ 45,965	$ 202,431	$ 63,128	$ 168,726	$ (33,705)	$ 180,818	$ 12,092	$ 180,818	$ 12,092
Provision for Rate Refunds		$ (361,129)	$ (361,129)	$ -	$ 361,129	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Government Assistance Directly Credited to Income		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,712	$ 12,712
SPC Recovery		$ -	$ -	$ 224,891	$ 224,891	$ 164,329	$ (60,562)	$ -	$ (164,329)	$ -	$ -	$ -	$ -
Gain on Disposition of Utility and Other Property		$ 14,336	$ 14,336	$ 400	$ (13,936)	$ 26,513	$ 26,113	$ (12,200)	$ (38,713)	$ 49,850	$ 62,050	$ (14,120)	$ (1,920)
Loss from Retirement of Utility and Other Property		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (30,000)	$ (30,000)	$ (30,000)	$ (30,000)
Revenues from Non-Utility Operations	$ (18,114)	$ 680,002	$ 698,116	$ 656,246	$ (23,756)	$ 739,783	$ 83,537	$ 879,343	$ 139,560	$ 668,839	$ (210,504)	$ 668,839	$ (210,504)
Expenses of Non-Utility Operations		$ (646,324)	$ (646,324)	$ (658,682)	$ (12,358)	$ (739,003)	$ (80,321)	$ (890,954)	$ (151,951)	$ (677,224)	$ 213,730	$ (677,101)	$ 213,853
Miscellaneous Non-Operating Income	$ 124,494	$ 182,056	$ 57,562	$ 251,896	$ 69,840	$ 277,307	$ 25,411	$ 278,000	$ 693	$ 272,000	$ (6,000)	$ 272,000	$ (6,000)
Foreign Exchange Gains and Losses, Including Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest and Dividend Income	$ 130,000	$ 159,335	$ 29,335	$ 178,369	$ 19,034	$ 747,158	$ 568,789	$ (99,807)	$ (846,965)	$ 110,390	$ 210,197	$ 110,390	$ 210,197
Total	**$ 1,497,790**	**$ 1,398,167**	**$ (99,623)**	**$ 2,039,134**	**$ 640,967**	**$ 2,653,018**	**$ 613,883**	**$ 1,557,714**	**$ (1,095,304)**	**$ 1,802,870**	**$ 245,156**	**$ 1,751,736**	$ 194,022
% of Total Revenue	**8%**	**8%**		**11%**		**13%**		**7%**		**8%**		**8%**	
Grand Total	**$ 18,603,746**	**$ 18,177,565**	**$ (426,181)**	**$ 18,543,198**	**$ 365,633**	**$ 20,048,083**	**$ 1,504,884**	**$ 23,072,966**	**$ 3,024,883**	**$ 21,703,925**	**$ (1,369,041)**	**$ 21,652,791**	**$ (1,420,176)**

2009 Actual vs. 2009 Board-Approved

- *Other Electric Revenues* – The variance of $90,627 is due to presentation only. The 2009 Board-approved budget is on a net revenue basis and the 2009 actuals are gross revenues.
- *Provision for Rate Refunds* - During the year, Thunder Bay Hydro received $361,129 from the IESO in connection with the Ontario Power Generation ("OPG") Rebate that was not known at the time of preparing the 2009 Board approved budget.
- *Revenues/Expenses from Non-Utility Operations* - The transactions that occur in these accounts are strictly related to the revenues and costs from the MSP services provided as described in Exhibit 1, Tab 1, Schedule 13. The net revenue for each year is less than the materiality threshold of $85,000.

2010 Actual vs. 2009 Actual

- *Provision for Rate Refunds* - During 2009, Thunder Bay Hydro received $361,129 from the IESO in connection with the Ontario Power Generation ("OPG") Rebate that did not occur in 2010. In addition, starting May 1, 2010, Thunder Bay Hydro recovered $224,891 from its customers in 2010 in regards to the Special Purpose Charge (SPC) that the MOE had invoiced all utilities that year. Recovery of the SPC was effective from May 1, 2010 to April 30, 2011.

2011 Actual vs 2010 Actual

- *Revenues/Expenses from Non-Utility Operations* - The transactions that occur in these accounts are strictly related to the revenues and costs from the MSP services provided as described in Exhibit 1, Tab 1, Schedule 13. The net revenue for each year is less than the materiality threshold of $85,000.
- *Interest and Dividend Income* – The increase in this account is a result of one-time transactions. In 2011 Thunder Bay Hydro received a decision from Canada Revenue Agency on the re-assessment of its tax return for 2003 and 2004 resulting in $326,000 in interest revenue earned on the over-payment of taxes. Also, in 2011, Thunder Bay Hydro was ordered by the Board in EB-2011-0197 to dispose of Account 1562 which resulted in a reduction of $199,960 of carrying charges.

2012 Bridge vs 2011 Actual

- *Revenues/Expenses from Non-Utility Operations* - The transactions that occur in these accounts are strictly related to the revenues and costs from the MSP services provided as described in Exhibit 1, Tab 1, Schedule 13. The net revenue for each year is less than the materiality threshold of $85,000.
- *Interest and Dividend Income* –The $846,965 reduction in Interest and Dividend is a combination of the receipt of one-time interest of $326,000 in 2011 as a result of a favourable decision from Canada Revenue Agency on the re-assessment of Thunder Bay Hydro's tax return for 2003 and 2004 earned on the over-payment of taxes; the recognition of a one-time reduction of $199,960 interest carrying charges as directed by the Board in EB-2011-0197 relating to the disposition of Account 1562; a 2012 adjustment to carrying charges relating to EB-2011-0197 for $77,000; the 2012 reversal of $133,000 of carrying charges representing the life-to-date interest on the Smart Meter deferral account as approved in EB-2012-0015; and $111,000 reduction due to regulatory asset balance changes.
- There is an unfavourable variance of $164,329 in the SPC Recovery since this rate rider ceased April 30, 2011.

2013 Bridge vs 2012 Actual

- *Revenues/Expenses from Non-Utility Operations* - The transactions that occur in these accounts are strictly related to the revenues and costs from the MSP services provided as described in Exhibit 1, Tab 1, Schedule 13. The net revenue for each year is less than the materiality threshold of $85,000.
- In 2012, carrying charges of $133,000 representing the life-to-date interest on the Smart Meter deferral account were reversed as approved in EB-2012-0015.

APPENDICES

Appendix 3-A

Monthly Data Used for Regression Analysis

Residential

	Consumed	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	CDM Activity	Predicted Consumed
Feb-99	30,944,887	719	0	28	0	0	31,374,405
Mar-99	31,192,273	710	0	31	1	0	32,869,009
Apr-99	27,103,570	408	0	30	1	0	27,740,904
May-99	25,155,491	225	3	31	1	0	26,068,191
Jun-99	23,427,104	92	11	30	0	0	24,540,251
Jul-99	24,261,259	24	59	31	0	0	26,063,014
Aug-99	24,804,295	74	12	31	0	0	25,149,205
Sep-99	24,983,512	194	6	30	1	0	24,903,557
Oct-99	27,927,642	423	0	31	1	0	28,795,026
Nov-99	30,807,188	501	0	30	1	0	29,061,045
Dec-99	36,673,911	817	0	31	0	0	35,277,753
Jan-00	38,014,660	964	0	31	0	0	37,355,910
Feb-00	32,921,591	712	0	29	0	0	32,107,718
Mar-00	31,183,992	575	0	31	1	0	30,945,578
Apr-00	27,040,375	486	0	30	1	0	28,846,699
May-00	25,265,965	261	0	31	1	0	26,486,908
Jun-00	23,296,607	156	2	30	0	0	25,132,762
Jul-00	23,900,945	56	21	31	0	0	25,185,364
Aug-00	24,355,355	63	10	31	0	0	24,916,153
Sep-00	24,440,428	223	0	30	1	0	25,123,334
Oct-00	27,797,990	372	0	31	1	0	28,072,497
Nov-00	31,881,933	562	0	30	1	0	29,925,524
Dec-00	37,787,463	1,041	0	31	0	0	38,460,286
Jan-01	38,555,413	899	0	31	0	0	36,437,490
Feb-01	32,616,109	919	0	28	0	0	34,216,257
Mar-01	32,556,214	703	0	31	1	0	32,763,966
Apr-01	28,157,362	431	0	30	1	0	28,067,390
May-01	25,958,483	240	0	31	1	0	26,194,490
Jun-01	23,827,611	114	15	30	0	0	24,984,721
Jul-01	24,764,453	67	30	31	0	0	25,654,858
Aug-01	25,255,805	40	56	31	0	0	26,180,022
Sep-01	24,913,988	188	7	30	1	0	24,851,979
Oct-01	27,835,723	409	0	31	1	0	28,589,197
Nov-01	30,318,951	459	0	30	1	0	28,466,272
Dec-01	35,374,340	716	0	31	0	0	33,848,310
Jan-02	36,712,336	874	0	31	0	0	36,084,033
Feb-02	32,266,196	733	0	28	0	0	31,577,394
Mar-02	33,150,979	805	0	31	1	0	34,211,863
Apr-02	28,627,065	462	0	30	1	0	28,515,954
May-02	26,571,397	335	1	31	1	0	27,561,646
Jun-02	24,748,365	114	14	30	0	0	24,955,988
Jul-02	25,888,517	18	79	31	0	0	26,661,790
Aug-02	26,199,143	50	16	31	0	0	24,917,819
Sep-02	25,956,181	144	21	30	1	0	24,709,742
Oct-02	29,475,966	510	0	31	1	0	30,029,996
Nov-02	31,967,183	668	0	30	1	0	31,435,879
Dec-02	36,868,027	786	0	31	0	0	34,830,608

Jan-03	38,700,757	907	0	31	0	0	36,559,567
Feb-03	34,507,023	970	0	28	0	0	34,935,947
Mar-03	34,325,570	765	0	31	1	0	33,649,738
Apr-03	28,484,612	499	0	30	1	0	29,041,172
May-03	26,044,983	276	0	31	1	0	26,712,610
Jun-03	24,018,304	129	0	30	0	0	24,678,869
Jul-03	25,420,951	30	18	31	0	0	24,729,664
Aug-03	26,294,358	36	51	31	0	0	25,935,792
Sep-03	26,006,212	164	7	30	1	0	24,512,115
Oct-03	29,293,414	414	0	31	1	0	28,668,690
Nov-03	32,018,999	633	0	30	1	0	30,937,633
Dec-03	36,958,309	786	0	31	0	0	34,834,867
Jan-04	38,668,459	1,141	0	31	0	0	39,869,856
Feb-04	34,331,411	778	0	29	0	0	33,055,949
Mar-04	32,611,182	684	0	31	1	0	32,502,777
Apr-04	28,276,429	472	0	30	1	0	28,659,325
May-04	26,338,968	333	0	31	1	0	27,518,889
Jun-04	23,894,673	146	3	30	0	0	25,019,759
Jul-04	24,543,278	67	22	31	0	0	25,392,738
Aug-04	25,024,173	123	2	31	0	0	25,486,896
Sep-04	25,064,195	133	5	30	1	0	24,001,828
Oct-04	28,414,630	373	0	31	1	0	28,079,594
Nov-04	31,681,876	555	0	30	1	0	29,830,417
Dec-04	37,366,130	927	0	31	0	0	36,832,112
Jan-05	38,920,097	1,084	0	31	0	0	39,070,674
Feb-05	33,256,365	756	0	28	0	0	31,902,461
Mar-05	32,485,848	814	0	31	1	0	34,345,296
Apr-05	27,843,394	408	0	30	1	0	27,746,582
May-05	26,410,478	306	0	31	1	0	27,135,622
Jun-05	24,942,453	73	17	30	0	0	24,452,101
Jul-05	26,102,159	45	53	31	0	0	26,145,745
Aug-05	26,089,422	46	30	31	0	0	25,354,740
Sep-05	25,222,663	149	15	30	1	0	24,588,837
Oct-05	28,188,329	347	0	31	1	0	27,719,040
Nov-05	31,328,732	607	0	30	1	0	30,568,561
Dec-05	35,177,920	833	0	31	0	0	35,509,132
Jan-06	35,617,692	797	0	31	0	41,619	34,940,163
Feb-06	31,119,249	873	0	28	0	83,239	33,465,843
Mar-06	31,449,484	659	0	31	1	124,858	31,986,834
Apr-06	26,877,889	366	0	30	1	166,477	26,939,893
May-06	25,562,475	242	2	31	1	208,097	26,038,440
Jun-06	24,435,693	82	9	30	0	249,716	24,006,745
Jul-06	26,098,783	23	70	31	0	291,336	26,054,565
Aug-06	26,170,049	58	32	31	0	332,955	25,170,671
Sep-06	25,175,887	211	1	30	1	374,574	24,512,506
Oct-06	28,107,342	441	0	31	1	416,194	28,525,005
Nov-06	30,295,182	540	0	30	1	457,813	29,049,627
Dec-06	34,491,263	747	0	31	0	499,432	33,661,126
Jan-07	36,622,949	913	0	31	0	500,110	36,016,655
Feb-07	33,051,424	925	0	28	0	500,788	33,669,655
Mar-07	32,838,996	665	0	31	1	501,466	31,599,027
Apr-07	27,187,576	474	0	30	1	502,143	28,052,820
May-07	25,075,511	251	1	31	1	502,821	25,739,795

Jun-07	23,606,364	97	7	30	0	503,499	23,807,439
Jul-07	25,024,283	40	52	31	0	504,176	25,398,869
Aug-07	25,405,765	63	22	31	0	504,854	24,698,261
Sep-07	24,742,490	165	10	30	1	505,532	23,986,950
Oct-07	27,723,957	311	0	31	1	506,210	26,562,338
Nov-07	30,827,409	620	0	30	1	506,887	30,122,181
Dec-07	35,599,989	926	0	31	0	507,565	36,183,312
Jan-08	36,928,192	935	0	31	0	534,914	36,275,301
Feb-08	33,416,716	922	0	29	0	562,263	34,382,543
Mar-08	32,183,546	792	0	31	1	589,611	33,289,680
Apr-08	27,644,920	457	0	30	1	616,960	27,664,468
May-08	25,783,649	328	0	31	1	644,309	26,631,637
Jun-08	23,754,145	110	5	30	0	671,657	23,718,245
Jul-08	24,747,665	35	22	31	0	699,006	24,054,127
Aug-08	25,143,285	50	22	31	0	726,355	24,246,084
Sep-08	24,523,776	193	7	30	1	753,704	23,991,786
Oct-08	27,526,933	373	0	31	1	781,052	27,104,358
Nov-08	31,226,745	591	0	30	1	808,401	29,327,598
Dec-08	37,155,502	1,034	0	31	0	835,750	37,304,215
Jan-09	38,353,900	1,093	0	31	0	822,624	38,166,726
Feb-09	32,500,593	839	0	28	0	809,497	32,064,014
Mar-09	32,075,058	762	0	31	1	796,371	32,609,839
Apr-09	27,709,882	453	0	30	1	783,245	27,403,112
May-09	25,569,750	320	0	31	1	770,119	26,361,493
Jun-09	23,459,495	142	14	30	0	756,992	24,377,030
Jul-09	24,048,969	75	2	31	0	743,866	23,871,105
Aug-09	24,478,400	84	14	31	0	730,740	24,445,088
Sep-09	24,618,194	103	4	30	1	717,613	22,632,022
Oct-09	27,456,122	451	0	31	1	704,487	28,311,989
Nov-09	29,904,969	474	0	30	1	691,361	27,806,667
Dec-09	34,964,951	915	0	31	0	678,235	35,814,244
Jan-10	36,057,478	900	0	31	0	665,521	35,621,542
Feb-10	30,130,234	778	0	28	0	652,808	31,401,996
Mar-10	28,883,687	514	0	31	1	640,095	29,287,148
Apr-10	25,214,912	358	0	30	1	627,382	26,247,488
May-10	24,552,386	212	1	31	1	614,668	25,052,817
Jun-10	23,935,373	106	3	30	0	601,955	23,699,625
Jul-10	25,887,089	15	52	31	0	589,242	24,934,105
Aug-10	26,150,279	38	56	31	0	576,529	25,412,995
Sep-10	24,537,525	231	0	30	1	563,816	24,525,966
Oct-10	26,385,460	356	0	31	1	551,102	27,143,316
Nov-10	29,631,901	549	0	30	1	538,389	29,076,188
Dec-10	34,660,039	879	0	31	0	525,676	35,497,657
Jan-11	36,485,116	1,078	0	31	0	545,207	38,295,106
Feb-11	31,514,007	827	0	28	0	564,739	32,201,062
Mar-11	31,195,447	750	0	31	1	584,271	32,700,195
Apr-11	26,991,352	482	0	30	1	603,802	28,041,548
May-11	24,638,198	267	0	31	1	623,334	25,796,339
Jun-11	23,225,198	110	0	30	0	642,865	23,598,957
Jul-11	25,328,857	30	64	31	0	662,397	25,462,015
Aug-11	25,888,764	22	36	31	0	681,928	24,366,116
Sep-11	24,573,928	172	9	30	1	701,460	23,841,887
Oct-11	26,460,412	337	5	31	1	720,992	26,856,000

Nov-11	28,829,236	563	0	30	1	740,523	29,018,222
Dec-11	32,475,587	770	0	31	0	760,055	33,651,783
Jan-12		965	0	31	0	740,246	36,453,570
Feb-12		827	0	29	0	720,438	32,841,040
Mar-12		708	0	31	1	700,629	31,952,846
Apr-12		443	0	30	1	680,821	27,384,335
May-12		277	1	31	1	661,012	25,902,371
Jun-12		113	8	30	0	641,204	23,908,261
Jul-12		40	42	31	0	621,395	24,911,216
Aug-12		58	28	31	0	601,586	24,686,203
Sep-12		175	7	30	1	581,778	23,940,481
Oct-12		394	0	31	1	561,969	27,684,903
Nov-12		563	0	30	1	542,161	29,267,343
Dec-12		860	0	31	0	522,352	35,227,539
Jan-13		965	0	31	0	536,745	36,709,144
Feb-13		827	0	28	0	551,137	32,218,144
Mar-13		708	0	31	1	565,530	32,122,515
Apr-13		443	0	30	1	579,923	27,511,051
May-13		277	1	31	1	594,315	25,986,135
Jun-13		113	8	30	0	608,708	23,949,072
Jul-13		40	42	31	0	623,100	24,909,074
Aug-13		58	28	31	0	637,493	24,641,108
Sep-13		175	7	30	1	651,885	23,852,434
Oct-13		394	0	31	1	666,278	27,553,903
Nov-13		563	0	30	1	680,671	29,093,390
Dec-13		860	0	31	0	695,063	35,010,633

General Service < 50 kW

	Consumed	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	CDM Activity	Predicted Consumed
Feb-99	17,327,916	719	0	28	0	0	13,129,085
Mar-99	17,359,595	710	0	31	1	0	13,127,443
Apr-99	15,664,135	408	0	30	1	0	11,660,691
May-99	13,519,281	225	3	31	1	0	11,088,772
Jun-99	11,067,497	92	11	30	0	0	10,986,620
Jul-99	11,931,408	24	59	31	0	0	11,823,675
Aug-99	11,870,805	74	12	31	0	0	11,089,679
Sep-99	10,678,451	194	6	30	1	0	10,854,893
Oct-99	11,511,566	423	0	31	1	0	11,891,090
Nov-99	11,957,904	501	0	30	1	0	12,061,321
Dec-99	13,635,988	817	0	31	0	0	14,045,152
Jan-00	15,330,630	964	0	31	0	0	14,675,822
Feb-00	13,820,224	712	0	29	0	0	13,262,127
Mar-00	13,391,805	575	0	31	1	0	12,543,729
Apr-00	12,031,970	486	0	30	1	0	11,996,272
May-00	11,503,054	261	0	31	1	0	11,190,633
Jun-00	11,209,216	156	2	30	0	0	11,078,200
Jul-00	11,730,066	56	21	31	0	0	11,184,037
Aug-00	11,661,961	63	10	31	0	0	10,995,683
Sep-00	10,980,047	223	0	30	1	0	10,866,323
Oct-00	11,662,354	372	0	31	1	0	11,671,820
Nov-00	12,675,810	562	0	30	1	0	12,323,669
Dec-00	15,116,275	1,041	0	31	0	0	15,010,972
Jan-01	15,154,298	899	0	31	0	0	14,397,104
Feb-01	13,641,937	919	0	28	0	0	13,991,517
Mar-01	13,648,088	703	0	31	1	0	13,095,565
Apr-01	11,856,072	431	0	30	1	0	11,759,771
May-01	11,342,215	240	0	31	1	0	11,101,891
Jun-01	11,131,038	114	15	30	0	0	11,158,350
Jul-01	11,725,875	67	30	31	0	0	11,412,811
Aug-01	11,877,643	40	56	31	0	0	11,828,157
Sep-01	11,035,991	188	7	30	1	0	10,849,906
Oct-01	11,725,612	409	0	31	1	0	11,828,626
Nov-01	12,317,933	459	0	30	1	0	11,880,822
Dec-01	13,753,117	716	0	31	0	0	13,611,352
Jan-02	14,717,580	874	0	31	0	0	14,289,838
Feb-02	13,558,642	733	0	28	0	0	13,190,687
Mar-02	14,209,911	805	0	31	1	0	13,534,966
Apr-02	12,272,587	462	0	30	1	0	11,895,899
May-02	11,551,603	335	1	31	1	0	11,521,637
Jun-02	11,122,434	114	14	30	0	0	11,139,935
Jul-02	12,307,378	18	79	31	0	0	12,199,307
Aug-02	11,929,053	50	16	31	0	0	11,051,455
Sep-02	11,239,413	144	21	30	1	0	10,943,453
Oct-02	11,801,422	510	0	31	1	0	12,265,873

Nov-02	12,822,029	668	0	30	1	0	12,782,024
Dec-02	14,078,380	786	0	31	0	0	13,909,455
Jan-03	14,832,051	907	0	31	0	0	14,434,151
Feb-03	13,779,216	970	0	28	0	0	14,209,925
Mar-03	13,829,301	765	0	31	1	0	13,364,375
Apr-03	11,430,989	499	0	30	1	0	12,055,290
May-03	10,893,804	276	0	31	1	0	11,259,128
Jun-03	10,521,915	129	0	30	0	0	10,918,154
Jul-03	11,128,406	30	18	31	0	0	11,020,534
Aug-03	11,424,089	36	51	31	0	0	11,703,621
Sep-03	10,536,500	164	7	30	1	0	10,745,796
Oct-03	11,282,978	414	0	31	1	0	11,852,750
Nov-03	12,256,111	633	0	30	1	0	12,630,819
Dec-03	13,505,417	786	0	31	0	0	13,910,747
Jan-04	14,816,218	1,141	0	31	0	0	15,438,742
Feb-04	13,887,024	778	0	29	0	0	13,549,891
Mar-04	13,418,397	684	0	31	1	0	13,016,300
Apr-04	11,743,989	472	0	30	1	0	11,939,408
May-04	11,392,997	333	0	31	1	0	11,503,814
Jun-04	10,739,166	146	3	30	0	0	11,051,663
Jul-04	11,518,787	67	22	31	0	0	11,258,605
Aug-04	11,273,129	123	2	31	0	0	11,091,322
Sep-04	10,874,645	133	5	30	1	0	10,571,544
Oct-04	11,638,624	373	0	31	1	0	11,673,974
Nov-04	12,406,565	555	0	30	1	0	12,294,806
Dec-04	14,682,122	927	0	31	0	0	14,516,862
Jan-05	15,490,461	1,084	0	31	0	0	15,196,210
Feb-05	13,456,928	756	0	28	0	0	13,289,337
Mar-05	13,345,814	814	0	31	1	0	13,575,459
Apr-05	11,242,470	408	0	30	1	0	11,662,414
May-05	11,077,310	306	0	31	1	0	11,387,502
Jun-05	10,921,397	73	17	30	0	0	11,012,227
Jul-05	11,811,198	45	53	31	0	0	11,787,698
Aug-05	11,621,456	46	30	31	0	0	11,320,763
Sep-05	10,756,551	149	15	30	1	0	10,851,494
Oct-05	11,210,250	347	0	31	1	0	11,564,555
Nov-05	12,421,437	607	0	30	1	0	12,518,814
Dec-05	14,062,601	833	0	31	0	0	14,115,370
Jan-06	14,013,676	797	0	31	0	0	13,958,564
Feb-06	12,950,909	873	0	28	0	0	13,795,509
Mar-06	13,056,672	659	0	31	1	0	12,907,312
Apr-06	10,960,003	366	0	30	1	0	11,481,053
May-06	10,857,342	242	2	31	1	0	11,157,117
Jun-06	10,711,254	82	9	30	0	0	10,899,528
Jul-06	11,590,985	23	70	31	0	0	12,036,864
Aug-06	11,267,214	58	32	31	0	0	11,412,163
Sep-06	10,346,111	211	1	30	1	0	10,835,349
Oct-06	11,074,716	441	0	31	1	0	11,967,769
Nov-06	11,839,321	540	0	30	1	0	12,232,342
Dec-06	13,000,063	747	0	31	0	0	13,744,895
Jan-07	14,034,124	913	0	31	0	0	14,459,998

Feb-07	13,411,306	925	0	28	0	0	14,016,502
Mar-07	13,154,355	665	0	31	1	0	12,933,159
Apr-07	11,133,755	474	0	30	1	0	11,946,732
May-07	10,478,239	251	1	31	1	0	11,161,361
Jun-07	10,400,462	97	7	30	0	0	10,908,619
Jul-07	11,106,520	40	52	31	0	0	11,741,561
Aug-07	10,983,624	63	22	31	0	0	11,241,234
Sep-07	10,226,521	165	10	30	1	0	10,807,213
Oct-07	10,659,751	311	0	31	1	0	11,406,456
Nov-07	11,710,802	620	0	30	1	0	12,576,540
Dec-07	13,516,776	926	0	31	0	0	14,513,416
Jan-08	14,079,991	935	0	31	0	1,283	14,545,126
Feb-08	13,315,074	922	0	29	0	2,566	14,153,516
Mar-08	12,851,057	792	0	31	1	3,849	13,459,937
Apr-08	11,201,981	457	0	30	1	5,132	11,846,119
May-08	10,635,429	328	0	31	1	6,414	11,446,973
Jun-08	10,307,060	110	5	30	0	7,697	10,887,442
Jul-08	11,035,092	35	22	31	0	8,980	11,073,346
Aug-08	10,909,092	50	22	31	0	10,263	11,136,363
Sep-08	10,089,218	193	7	30	1	11,546	10,818,392
Oct-08	10,590,623	373	0	31	1	12,829	11,609,402
Nov-08	11,878,621	591	0	30	1	14,112	12,377,395
Dec-08	13,923,680	1,034	0	31	0	15,395	14,899,109
Jan-09	14,774,043	1,093	0	31	0	30,035	15,080,202
Feb-09	12,722,573	839	0	28	0	44,675	13,416,023
Mar-09	12,883,690	762	0	31	1	59,315	13,045,792
Apr-09	10,966,406	453	0	30	1	73,955	11,474,521
May-09	10,461,417	320	0	31	1	88,595	10,988,256
Jun-09	9,990,702	142	14	30	0	103,235	10,714,413
Jul-09	10,317,886	75	2	31	0	117,875	10,277,276
Aug-09	10,370,104	84	14	31	0	132,516	10,489,097
Sep-09	10,101,127	103	4	30	1	147,156	9,657,257
Oct-09	10,536,289	451	0	31	1	161,796	11,176,891
Nov-09	11,111,942	474	0	30	1	176,436	11,032,381
Dec-09	13,226,423	915	0	31	0	191,076	13,479,038
Jan-10	13,828,628	900	0	31	0	191,710	13,412,437
Feb-10	11,981,794	778	0	28	0	192,344	12,392,290
Mar-10	11,486,667	514	0	31	1	192,978	11,287,147
Apr-10	10,122,295	358	0	30	1	193,612	10,446,065
May-10	10,173,340	212	1	31	1	194,246	9,991,707
Jun-10	9,917,199	106	3	30	0	194,880	9,872,412
Jul-10	10,665,572	15	52	31	0	195,514	10,624,524
Aug-10	10,773,213	38	56	31	0	196,147	10,798,579
Sep-10	9,493,420	231	0	30	1	196,781	9,883,019
Oct-10	10,050,092	356	0	31	1	197,415	10,579,698
Nov-10	11,126,353	549	0	30	1	198,049	11,247,656
Dec-10	13,159,976	879	0	31	0	198,683	13,285,506
Jan-11	14,305,983	1,078	0	31	0	204,314	14,112,808
Feb-11	12,447,477	827	0	28	0	209,945	12,510,263
Mar-11	12,511,170	750	0	31	1	215,576	12,184,865
Apr-11	10,795,312	482	0	30	1	221,207	10,838,926

May-11	10,116,497	267	0	31	1	226,838	10,046,405
Jun-11	9,660,217	110	0	30	0	232,469	9,634,114
Jul-11	10,698,072	30	64	31	0	238,100	10,705,981
Aug-11	10,773,480	22	36	31	0	243,731	10,080,261
Sep-11	9,905,487	172	9	30	1	249,362	9,547,298
Oct-11	10,393,024	337	5	31	1	254,993	10,312,067
Nov-11	11,403,016	563	0	30	1	260,625	10,983,735
Dec-11	12,720,099	770	0	31	0	266,256	12,465,465
Jan-12		965	0	31	0	261,491	13,332,811
Feb-12		827	0	29	0	256,726	12,432,572
Mar-12		708	0	31	1	251,961	11,814,384
Apr-12		443	0	30	1	247,197	10,534,527
May-12		277	1	31	1	242,432	10,017,357
Jun-12		113	8	30	0	237,667	9,775,145
Jul-12		40	42	31	0	232,903	10,338,167
Aug-12		58	28	31	0	228,138	10,147,930
Sep-12		175	7	30	1	223,373	9,642,415
Oct-12		394	0	31	1	218,608	10,642,707
Nov-12		563	0	30	1	213,844	11,225,484
Dec-12		860	0	31	0	209,079	13,148,544
Jan-13		965	0	31	0	213,111	13,582,825
Feb-13		827	0	28	0	217,142	12,473,071
Mar-13		708	0	31	1	221,174	11,973,483
Apr-13		443	0	30	1	225,206	10,648,170
May-13		277	1	31	1	229,237	10,085,543
Jun-13		113	8	30	0	233,269	9,797,873
Jul-13		40	42	31	0	237,301	10,315,439
Aug-13		58	28	31	0	241,332	10,079,744
Sep-13		175	7	30	1	245,364	9,528,773
Oct-13		394	0	31	1	249,396	10,483,607
Nov-13		563	0	30	1	253,427	11,020,927
Dec-13		860	0	31	0	257,459	12,898,530

General Service > 50 to 999 kW

	Consumed	Heating Degree Days	Cooling Degree Days	Number of Days in Month	Spring Fall Flag	CDM Activity	Ontario Real GDP Monthly %	Number of Customers	Number of Peak Hours	Predicted Consumed
Feb-99	27,689,061	719	0	28	0	0	106.09	578	320	25,895,107
Mar-99	28,367,059	710	0	31	1	0	106.73	583	368	26,821,944
Apr-99	24,673,274	408	0	30	1	0	107.38	596	336	23,465,323
May-99	23,679,738	225	3	31	1	0	108.03	611	320	22,238,507
Jun-99	20,438,075	92	11	30	0	0	108.68	616	352	21,950,639
Jul-99	21,927,428	24	59	31	0	0	109.34	619	336	23,548,718
Aug-99	22,070,964	74	12	31	0	0	110.00	626	336	22,153,670
Sep-99	21,905,566	194	6	30	1	0	110.67	640	336	22,040,137
Oct-99	23,608,817	423	0	31	1	0	111.34	647	320	24,202,153
Nov-99	24,880,229	501	0	30	1	0	112.01	647	352	24,816,474
Dec-99	28,520,683	817	0	31	0	0	112.69	333	336	27,032,387
Jan-00	30,116,383	964	0	31	0	0	113.21	647	320	29,819,445
Feb-00	26,672,243	712	0	29	0	0	113.73	601	336	26,655,265
Mar-00	25,141,922	575	0	31	1	0	114.25	562	368	25,649,468
Apr-00	22,143,192	486	0	30	1	0	114.77	517	304	23,661,332
May-00	20,987,165	261	0	31	1	0	115.30	497	352	22,333,086
Jun-00	19,836,290	156	2	30	0	0	115.83	452	352	21,502,128
Jul-00	21,238,167	56	21	31	0	0	116.36	431	320	21,351,160
Aug-00	21,418,208	63	10	31	0	0	116.90	429	352	21,261,536
Sep-00	20,859,271	223	0	30	1	0	117.43	428	320	21,017,280
Oct-00	22,319,549	372	0	31	1	0	117.97	434	336	22,958,821
Nov-00	24,898,435	562	0	30	1	0	118.52	438	352	24,467,165
Dec-00	29,608,811	1,041	0	31	0	0	119.06	439	304	29,477,111
Jan-01	29,257,180	899	0	31	0	0	119.23	473	352	28,770,353
Feb-01	27,178,451	919	0	28	0	0	119.40	477	320	27,517,026
Mar-01	26,804,324	703	0	31	1	0	119.58	476	352	26,362,876
Apr-01	22,932,703	431	0	30	1	0	119.75	474	320	23,195,856
May-01	21,898,869	240	0	31	1	0	119.92	476	352	22,144,185
Jun-01	21,021,876	114	15	30	0	0	120.10	477	336	21,725,185
Jul-01	21,695,834	67	30	31	0	0	120.27	476	336	22,275,023
Aug-01	22,267,607	40	56	31	0	0	120.45	475	352	23,230,032
Sep-01	20,970,044	188	7	30	1	0	120.62	474	304	21,131,227
Oct-01	22,726,743	409	0	31	1	0	120.80	476	352	23,704,652
Nov-01	23,917,782	459	0	30	1	0	120.97	478	352	23,785,715
Dec-01	26,175,856	716	0	31	0	0	121.15	477	304	26,748,843
Jan-02	28,530,795	874	0	31	0	0	121.50	477	352	28,614,737
Feb-02	26,198,686	733	0	28	0	0	121.86	475	320	25,865,059
Mar-02	27,472,386	805	0	31	1	0	122.22	478	320	27,082,833
Apr-02	23,674,636	462	0	30	1	0	122.59	480	352	23,864,433
May-02	22,507,068	335	1	31	1	0	122.95	485	352	23,146,905
Jun-02	22,085,684	114	14	30	0	0	123.31	484	320	21,650,914
Jul-02	23,193,556	18	79	31	0	0	123.68	478	352	24,050,819
Aug-02	22,417,126	50	16	31	0	0	124.04	481	336	21,653,152

Sep-02	21,763,822	144	21	30	1	0	124.41	483	320	21,567,305
Oct-02	23,906,577	510	0	31	1	0	124.78	488	352	24,782,505
Nov-02	25,919,156	668	0	30	1	0	125.14	491	336	25,717,085
Dec-02	27,992,723	786	0	31	0	0	125.51	488	320	27,673,106
Jan-03	30,247,356	907	0	31	0	0	125.66	489	352	29,075,568
Feb-03	28,460,283	970	0	28	0	0	125.81	492	320	28,201,069
Mar-03	28,715,022	765	0	31	1	0	125.95	505	336	27,086,101
Apr-03	23,920,980	499	0	30	1	0	126.10	499	336	24,238,382
May-03	22,761,854	276	0	31	1	0	126.24	499	336	22,599,398
Jun-03	21,516,931	129	0	30	0	0	126.39	503	336	21,525,671
Jul-03	22,581,221	30	18	31	0	0	126.54	500	352	21,871,306
Aug-03	22,725,768	36	51	31	0	0	126.68	499	320	22,959,116
Sep-03	22,003,814	164	7	30	1	0	126.83	503	336	21,483,322
Oct-03	24,158,122	414	0	31	1	0	126.98	499	352	24,012,140
Nov-03	25,919,367	633	0	30	1	0	127.12	500	320	25,341,016
Dec-03	27,963,039	786	0	31	0	0	127.27	501	336	27,925,442
Jan-04	30,937,975	1,141	0	31	0	0	127.53	499	336	31,160,653
Feb-04	27,306,089	778	0	29	0	0	127.80	486	320	26,864,460
Mar-04	26,515,207	684	0	31	1	0	128.06	460	368	26,451,067
Apr-04	23,016,462	472	0	30	1	0	128.32	457	336	23,831,625
May-04	21,892,354	333	0	31	1	0	128.59	459	320	22,825,644
Jun-04	20,420,159	146	3	30	0	0	128.85	459	352	21,775,139
Jul-04	21,540,775	67	22	31	0	0	129.12	461	336	22,091,583
Aug-04	21,313,849	123	2	31	0	0	129.38	463	336	21,800,543
Sep-04	21,313,094	133	5	30	1	0	129.65	466	336	20,996,225
Oct-04	22,910,608	373	0	31	1	0	129.92	465	320	23,246,831
Nov-04	24,309,383	555	0	30	1	0	130.19	465	352	24,807,187
Dec-04	28,308,963	927	0	31	0	0	130.45	464	336	29,096,220
Jan-05	29,981,056	1,084	0	31	0	0	130.74	466	320	30,408,940
Feb-05	26,021,217	756	0	28	0	0	131.03	466	320	26,237,184
Mar-05	27,186,436	814	0	31	1	0	131.33	487	352	27,702,578
Apr-05	23,539,060	408	0	30	1	0	131.62	481	336	23,440,176
May-05	23,356,657	306	0	31	1	0	131.91	483	336	22,919,641
Jun-05	22,845,170	73	17	30	0	0	132.20	482	352	21,851,358
Jul-05	23,894,016	45	53	31	0	0	132.50	484	320	23,188,904
Aug-05	23,530,513	46	30	31	0	0	132.79	480	352	22,522,301
Sep-05	22,573,270	149	15	30	1	0	133.09	481	336	21,718,688
Oct-05	23,998,835	347	0	31	1	0	133.38	483	320	23,184,285
Nov-05	26,134,847	607	0	30	1	0	133.68	482	352	25,447,120
Dec-05	29,015,605	833	0	31	0	0	133.98	483	320	28,276,677
Jan-06	28,857,836	797	0	31	0	0	134.25	484	336	28,099,718
Feb-06	27,077,340	873	0	28	0	0	134.53	483	320	27,475,323
Mar-06	27,505,940	659	0	31	1	0	134.81	492	368	26,534,531
Apr-06	23,111,767	366	0	30	1	0	135.08	505	304	22,970,026
May-06	22,990,550	242	2	31	1	0	135.36	495	352	22,702,083
Jun-06	22,533,457	82	9	30	0	0	135.64	493	352	21,763,589
Jul-06	24,301,816	23	70	31	0	0	135.92	497	320	23,820,221
Aug-06	23,835,760	58	32	31	0	0	136.20	493	352	22,854,080
Sep-06	22,400,469	211	1	30	1	0	136.48	492	320	21,704,050
Oct-06	24,231,401	441	0	31	1	0	136.76	491	336	24,300,339

Nov-06	25,214,981	540	0	30	1	0	137.04	491	352	24,961,590
Dec-06	27,155,476	747	0	31	0	0	137.33	494	304	27,485,197
Jan-07	29,676,421	913	0	31	0	0	137.55	493	352	29,420,694
Feb-07	28,282,810	925	0	28	0	0	137.78	492	320	28,063,039
Mar-07	27,525,693	665	0	31	1	0	138.01	494	352	26,527,978
Apr-07	23,467,013	474	0	30	1	0	138.23	511	320	24,198,607
May-07	22,478,394	251	1	31	1	0	138.46	502	352	22,821,054
Jun-07	22,019,744	97	7	30	0	0	138.69	500	336	21,754,538
Jul-07	23,321,554	40	52	31	0	0	138.92	501	336	23,469,693
Aug-07	23,240,095	63	22	31	0	0	139.15	503	352	22,631,705
Sep-07	22,268,313	165	10	30	1	0	139.38	503	304	21,606,470
Oct-07	23,251,142	311	0	31	1	0	139.61	502	352	23,368,128
Nov-07	25,216,953	620	0	30	1	0	139.84	500	352	25,800,205
Dec-07	28,289,376	926	0	31	0	0	140.07	505	304	29,232,287
Jan-08	29,941,523	935	0	31	0	3,328	139.97	506	352	29,724,290
Feb-08	28,646,777	922	0	29	0	6,656	139.86	508	320	28,531,662
Mar-08	27,818,163	792	0	31	1	9,984	139.76	507	304	27,333,969
Apr-08	23,652,682	457	0	30	1	13,312	139.65	511	352	24,310,071
May-08	22,308,976	328	0	31	1	16,641	139.55	506	336	23,342,495
Jun-08	21,249,668	110	5	30	0	19,969	139.44	503	336	21,756,038
Jul-08	22,972,098	35	22	31	0	23,297	139.34	504	352	22,299,707
Aug-08	22,825,673	50	22	31	0	26,625	139.23	504	320	22,150,836
Sep-08	21,467,073	193	7	30	1	29,953	139.13	504	336	21,936,659
Oct-08	22,471,775	373	0	31	1	33,281	139.02	510	352	23,845,935
Nov-08	24,888,470	591	0	30	1	36,609	138.92	517	304	25,041,078
Dec-08	29,306,803	1,034	0	31	0	39,937	138.81	507	336	30,334,468
Jan-09	30,390,442	1,093	0	31	0	61,373	138.39	507	336	30,791,427
Feb-09	26,263,964	839	0	28	0	82,809	137.97	509	304	26,929,320
Mar-09	27,251,713	762	0	31	1	104,245	137.54	505	352	27,084,312
Apr-09	23,432,845	453	0	30	1	125,681	137.13	509	320	23,519,561
May-09	22,192,428	320	0	31	1	147,116	136.71	511	320	22,617,052
Jun-09	21,367,059	142	14	30	0	168,552	136.29	512	352	21,990,447
Jul-09	21,786,905	75	2	31	0	189,988	135.87	517	352	21,234,764
Aug-09	21,830,455	84	14	31	0	211,424	135.46	509	320	21,406,245
Sep-09	21,745,883	103	4	30	1	232,859	135.05	500	336	20,120,411
Oct-09	22,904,447	451	0	31	1	254,295	134.63	498	336	23,458,602
Nov-09	23,624,772	474	0	30	1	275,731	134.22	496	320	23,029,451
Dec-09	27,995,597	915	0	31	0	297,167	133.81	500	352	28,308,028
Jan-10	28,848,754	900	0	31	0	289,685	134.14	500	320	27,926,567
Feb-10	25,285,561	778	0	28	0	282,204	134.47	499	304	25,524,114
Mar-10	24,774,551	514	0	31	1	274,723	134.81	504	368	24,275,877
Apr-10	21,802,131	358	0	30	1	267,241	135.14	502	320	22,056,456
May-10	21,546,326	212	1	31	1	259,760	135.47	504	320	21,188,661
Jun-10	21,148,669	106	3	30	0	252,278	135.81	507	352	20,894,806
Jul-10	23,011,995	15	52	31	0	244,797	136.14	508	336	22,325,042
Aug-10	22,902,957	38	56	31	0	237,316	136.48	505	336	22,711,686
Sep-10	21,445,061	231	0	30	1	229,834	136.81	510	336	21,252,443
Oct-10	22,479,587	356	0	31	1	222,353	137.15	510	320	22,675,343
Nov-10	24,032,348	549	0	30	1	214,871	137.49	515	336	24,254,153
Dec-10	27,766,415	879	0	31	0	207,390	137.83	516	368	28,619,356

Jan-11	29,459,468	1,078	0	31	0	206,108	138.03	499	336	30,076,714
Feb-11	26,055,811	827	0	28	0	204,827	138.24	500	304	26,338,159
Mar-11	26,578,325	750	0	31	1	203,545	138.44	505	368	26,772,377
Apr-11	23,072,765	482	0	30	1	202,263	138.65	506	320	23,527,176
May-11	21,823,871	267	0	31	1	200,982	138.86	507	336	22,109,146
Jun-11	20,705,190	110	0	30	0	199,700	139.06	507	352	21,073,118
Jul-11	22,579,865	30	64	31	0	198,418	139.27	503	320	23,009,921
Aug-11	22,784,074	22	36	31	0	197,137	139.48	507	352	22,122,249
Sep-11	21,345,136	172	9	30	1	195,855	139.69	506	336	21,262,951
Oct-11	22,769,113	337	5	31	1	194,573	139.89	508	320	22,879,003
Nov-11	24,230,624	563	0	30	1	193,292	140.10	509	352	24,628,440
Dec-11	26,954,814	770	0	31	0	192,010	140.31	512	336	27,431,297
Jan-12		965	0	31	0	193,095	140.52	511	336	29,214,128
Feb-12		827	0	29	0	194,179	140.73	510	320	27,018,531
Mar-12		708	0	31	1	195,264	140.94	509	352	26,352,946
Apr-12		443	0	30	1	196,348	141.15	508	320	23,256,787
May-12		277	1	31	1	197,433	141.36	507	352	22,430,237
Jun-12		113	8	30	0	198,517	141.57	507	336	21,329,120
Jul-12		40	42	31	0	199,601	141.78	507	336	22,436,603
Aug-12		58	28	31	0	200,686	141.99	507	352	22,156,932
Sep-12		175	7	30	1	201,770	142.20	507	304	20,943,438
Oct-12		394	0	31	1	202,855	142.41	507	352	23,496,377
Nov-12		563	0	30	1	203,939	142.62	507	352	24,636,744
Dec-12		860	0	31	0	205,024	142.83	507	304	27,956,229
Jan-13		965	0	31	0	204,106	143.13	507	352	29,354,189
Feb-13		827	0	28	0	203,189	143.42	507	304	26,497,933
Mar-13		708	0	31	1	202,271	143.72	507	320	26,098,471
Apr-13		443	0	30	1	201,353	144.02	507	352	23,580,102
May-13		277	1	31	1	200,436	144.31	507	352	22,485,843
Jun-13		113	8	30	0	199,518	144.61	507	320	21,257,940
Jul-13		40	42	31	0	198,600	144.91	508	352	22,656,500
Aug-13		58	28	31	0	197,683	145.21	508	336	22,104,243
Sep-13		175	7	30	1	196,765	145.50	508	320	21,181,840
Oct-13		394	0	31	1	195,848	145.80	508	352	23,603,123
Nov-13		563	0	30	1	194,930	146.10	508	336	24,611,841
Dec-13		860	0	31	0	194,012	146.41	508	320	28,222,438

Appendix 3-B

OPA Final Evaluation Report

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2011 Results Report.

Despite some of the inertial challenges in 2011 with program start up, on average, year one province-wide forecasts were met and the year finished out with strong momentum which continues to build 2012. There are still challenges for LDCs of all sizes and we are committed to ensuring LDCs are successful in meeting their objectives. We look forward to further dialogue to discover opportunities to improve the current program suite with local program opportunities, best practices and successes to better reach our customers in the years to come.

This report was developed in collaboration with the OPA-LDC Reporting and Evaluation Working Group and is designed to help populate LDC annual report templates that will be submitted to the OEB in late September. Between the draft and final reports several improvements were made to improve clarity and transparency based on feedback provided by LDCs, such as: the addition of a glossary tab, total adjustments to savings are now broken out into both the realization rate and net-to-gross ratio for both peak demand and energy savings and modifications were made to the methodology tab. We invite you to continue to provide your feedback.

All results are now considered final for 2011. Any additional 2011 program activity not captured will be reported in the Final 2012 Results Report. Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year in 2012.

Sincerely,
Andrew Pride

Table of Contents

Summary	Provides a "snapshot" of your LDC's OPA-Contracted Province-Wide Program performance in 2011: progress to target using 2 scenarios, sector breakdown and progress against the LDC community.
LDC-Specific Data: table formats, section references and table numbers align with the OEB Reporting Template	
2.3 Results Participation - LDC	Breakdown of initiative-level participation in 2011 for your LDC.
2.5.1 Evaluation Findings	Provides a summary of the province-wide evaluation findings for each initiative and highlights which initiatives were not evaluated.
2.5.2 Results - LDC	Provides LDC-specific initiative-level results (net and gross peak demand and energy savings, realization rates, net-to-gross ratios and how each initiative contributes to target)
3.1.1 Summary - LDC	Provides a portfolio level view of achievement towards your OEB targets in 2011. Contains space to input LDC-specific progress to milestones set out in your CDM Strategy.
Province-Wide Data: LDC performance in aggregate (province-wide results)	
Provincial - Participation	Breakdown of initiative-level participation in 2011 for the province.
Provincial - Results	Provides province-wide initiative-level results (net and gross peak demand and energy savings, realization rates, net-to-gross ratios and how each initiative contributes to target)
Provincial - Progress Summary	Provides a portfolio level view of provincial achievement towards province-wide OEB targets in 2011.
Methodology	Provides key equations, notes and an initiative-level breakdown of: how savings are attributed to LDCs, when the savings are considered to 'start' (i.e. what period the savings are attributed to) and how the savings are calculated.
Reference Tables	Provides the sector mapping used for Retrofit and the allocation methodology table used in the consumer program when customer specific information is unavailable
Glossary	Contains definitions for terms used throughout the report.

OPA-Contracted Province-Wide CDM Programs FINAL 2011 Results

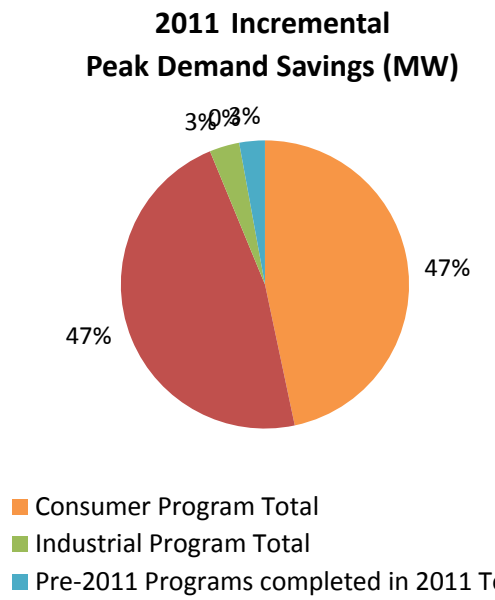
LDC: Thunder Bay Hydro Electricity Distribution Inc.

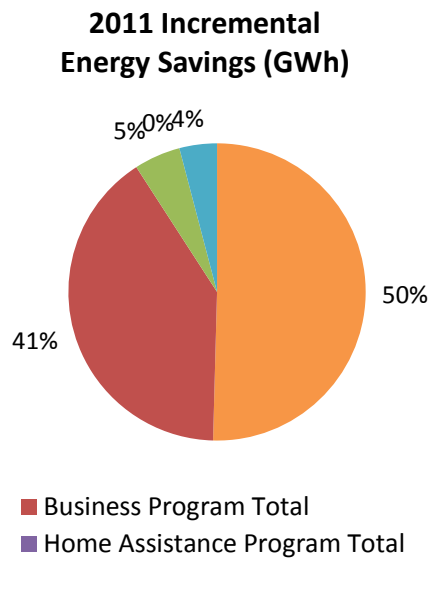
FINAL 2011 Progress to Targets	Incremental 2011	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	0.5	**5.6%**	**6.2%**
Net Cumulative Energy Savings (GWh)	2.2	**17.9%**	**17.9%**

Scenario 1 = Assumes that demand resource resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in your territory until 2014

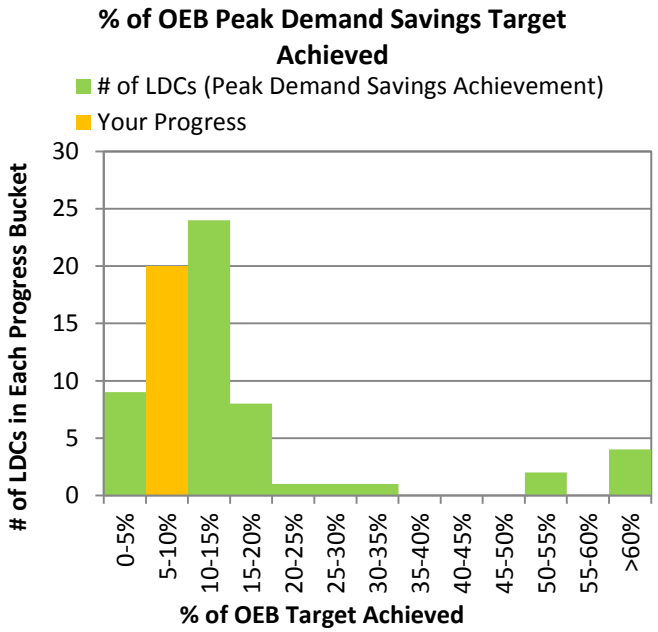
Achievement by Sector





Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)



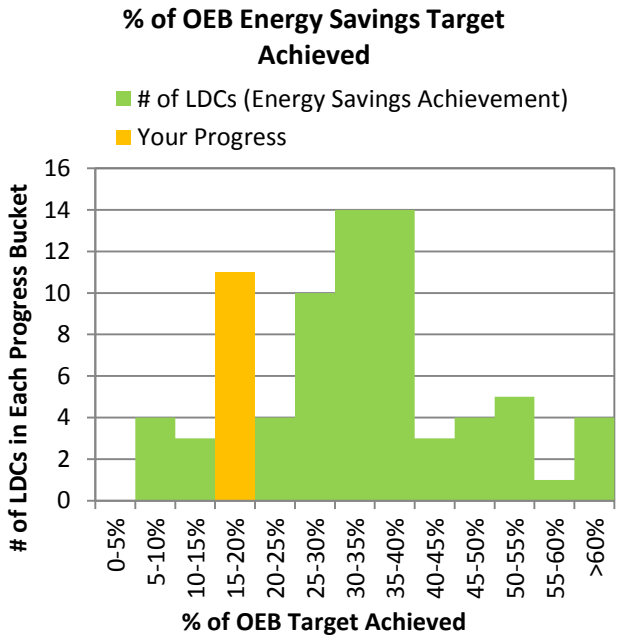


Table 1: Participation[1]

#	Initiative	Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	720
2	Appliance Exchange	Appliances	14
3	HVAC Incentives	Equipment	522
4	Conservation Instant Coupon Booklet	Products	4,461
5	Bi-Annual Retailer Event	Products	7,605
6	Retailer Co-op	Products	0
7	Residential Demand Response	Devices	0
8	Residential New Construction	Houses	0
Business Program			
9	Efficiency: Equipment Replacement	Projects	37
10	Direct Install Lighting	Projects	76
11	Existing Building Commissioning Incentive	Buildings	0
12	New Construction and Major Renovation Incentive	Buildings	0
13	Energy Audit	Audits	3
14	Commercial Demand Response (part of the Residential program schedule)	Devices	0
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	0
Industrial Program			
16	Process & System Upgrades	Projects[2]	0
17	Monitoring & Targeting	Projects[3]	0
18	Energy Manager	Managers[2 3]	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Projects	2
20	Demand Response 3	Facilities	0
Home Assistance Program			
21	Home Assistance Program	Homes	0
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	12
23	High Performance New Construction	Projects	0
24	Toronto Comprehensive	Projects	0
25	Multifamily Energy Efficiency Rebates	Projects	0
26	Data Centre Incentive Program	Projects	0
27	EnWin Green Suites	Projects	0

[1] *Please see "Methodology" tab for more information regarding attributing savings to LDCs*

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers if projects are completed in 2011*

Table 3: OPA Province-Wide Evaluation Findings

#	Initiative	OPA Province-Wide Key Evaluation Findings
Consumer Program		
1	Appliance Retirement	* Overall participation continues to decline year over year * Participation declined 17% from 2010 (from over 67,000 units in 2010 to over 56,000 units in 2011) * 97% of net resource savings achieved through the home pick-up stream * Measure Breakdown: 66% refrigerators, 30% freezers, 4% Dehumidifiers and window air conditioners * 3% of net resource savings achieved through the Retailer pick-up stream * Measure Breakdown: 90% refrigerators, 10% freezers * Net-to-Gross ratio for the initiative was 50% * Measure-level free ridership ranges from 82% for the retailer pick-up stream to 49% for the home pick-up stream * Measure-level spillover ranges from 3.7% for the retailer pick-up stream to 1.7% for the home pick-up stream
2	Appliance Exchange	* Overall eligible units exchanged declined by 36% from 2010 (from over 5,700 units in 2010 to * Measure Breakdown: 75% window air conditioners, 25% dehumidifiers * Dehumidifiers and window air conditioners contributed almost equally to the net energy * Dehumidifiers provide more than three times the energy savings per unit than window air conditioners * Window air conditioners contributed to 64% of the net peak demand savings achieved * Approximately 96% of consumers reported having replaced their exchanged units (as opposed to retiring the unit) * Net-to-Gross ratio for the initiative is consistent with previous evaluations (51.5%)
3	HVAC Incentives	* Total air conditioner and furnace installations increased by 14% (from over 95,800 units in 2010 to over 111,500 units in 2011) * Measure Breakdown: 64% furnaces, 10% tier 1 air conditioners (SEER 14.5) and 26% tier 2 air conditioners (SEER 15) * Measure breakdown did not change from 2010 to 2011 * The HVAC Incentives initiative continues to deliver the majority of both the energy (45%) and demand (83%) savings in the consumer program * Furnaces accounted for over 91% of energy savings achieved for this initiative * Net-to-Gross ratio for the initiative was 17% higher than 2010 (from 43% in 2010 to 60% in * Increase due in part to the removal of programmable thermostats from the program, and an increase in the net-to-gross ratio for both Furnaces and Tier 2 air conditioners (SEER 15)
4	Conservation Instant Coupon Booklet	* Customers redeemed nearly 210,000 coupons, translating to nearly 560,000 products * Majority of coupons redeemed were downloadable (~40%) or LDC-branded (~35%) * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (37%), followed by multi-packs of specialty CFLs (17%) * Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings * Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed
		* Customers redeemed nearly 370,000 coupons, translating to over 870,000 products * Majority of coupons redeemed were for multi-packs of standard spiral CFLs (49%), followed by multi-packs of specialty CFLs (16%)

#	Initiative	OPA Province-Wide Key Evaluation Findings

5	Bi-Annual Retailer Event	* Per unit savings estimates and net-to-gross ratios for 2011 are based on a weighted average of 2009 and 2010 evaluation findings
		  * Standard CFLs and heavy duty outdoor timers were reintroduced to the initiative in 2011 and contributed more than 64% of the initiative's 2011 net annual energy savings
		  * While the volume of coupons redeemed for heavy duty outdoor timers was relatively small (less than 1%), the measure accounted for 10% of net annual savings due to high per unit savings
		* Careful attention in the 2012 evaluation will be made for standard CFLs since it is believed that the market has largely been transformed.

6	Retailer Co-op	* Initiative was not evaluated in 2011 due to low uptake. Verified Bi-Annual Retailer Event per unit assumptions and free-ridership rates were used to calculate net resource savings

7	Residential Demand Response	* Approximately 20,000 new devices were installed in 2011
		  * 99% of the new devices enrolled controlled residential central AC (CAC)
		* 2011 only saw 1 atypical event (in both weather and timing) that had limited participation
		  * The ex ante impact developed through the 2009/2010 evaluations was maintained for 2011; residential CAC: 0.56 kW/device, commercial CAC: 0.64 kW/device, and Electric Water Heaters: 0.30 kW/device

8	Residential New Construction	* Initiative was not evaluated in 2011 due to limited uptake * Business case assumptions were used to calculate savings
Business Program		

9	Efficiency: Equipment Replacement	* Gross verified energy savings were boosted by lighting projects in the prescriptive and
		* Lighting projects overall were determined to have a realization rate of 112%; 116% when including interactive energy changes
		  * On average, the evaluation found high realization rates as a result of both longer operating hours and larger wattage reductions than initial assumptions
		  * Low realization rates for engineered lighting projects due to overstated operating hour assumptions
		* Custom non-lighting projects suffered from process issues such as: the absence of required M&V plans, the use of inappropriate assumptions , and the lack of adherence to the M&V plan
		* The final realization rate for summer peak demand was 94%
		  * 84% was a result of different methodologies used to calculate peak demand savings
		  * 10% due to the benefits from reduced air conditioning load in lighting retrofits
		* Overall net-to-gross ratios in the low 70's represent an improvement over the 2009 and Strict eligibility requirements and improvements in the pre-approval process contributed to the improvement in net-to-gross ratios

10	Direct Install Lighting	* Though overall performance is above expectations, participation continues to decline year over year as the initiative reaches maturity
		* 70% of province-wide resource savings persist to 2014
		  * Over 35% of the projects for 2011 included at least one CFL measure
		  * Resource savings from CFLs in the commercial sector only persist for the industry standard of 3 years
		* Since 2009 the overall realization rate for this program has improved
		  * 2011 evaluation recorded the highest energy realization rate to date at 89.5%

#	Initiative	OPA Province-Wide Key Evaluation Findings
		* The hours of use values were held constant from the 2010 evaluation and continue to be the main driver of energy realization rate * Lights installed in "as needed" areas (e.g., bathrooms, storage areas) were determined to have very low realization rates due to the difference in actual energy saved vs. reported savings
11	Existing Building Commissioning Incentive	* Initiative was not evaluated in 2011, no completed projects in 2011
12	New Construction and Major Renovation Incentive	* Initiative was not evaluated in 2011 due to low uptake * Assumptions used are consistent with preliminary reporting based on the 2010 Evaluation findings and consultation with the C&I Work Group (100% realization rate and 50% net-to-gross ratio)
13	Energy Audit	* The evaluation is ongoing. The sample size for 2011 was too small to draw reliable conclusions.
14	Commercial Demand Response (part of the Residential program schedule)	* See residential demand response (#7)
15	Demand Response 3 (part of the Industrial program schedule)	* See Demand Response 3 (#20)
Industrial Program		
16	Process & System Upgrades	* Initiative was not evaluated in 2011, no completed projects in 2011
17	Monitoring & Targeting	* Initiative was not evaluated in 2011, no completed projects in 2011
18	Energy Manager	* Initiative was not evaluated in 2011, no completed projects in 2011
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	* See Efficiency: Equipment Replacement (#9)
20	Demand Response 3	* Program performance for Tier 1 customers increased with DR-3 participants providing 75% * Industrial customers outperform commercial customers by provide 84% and 76% of contracted MW, respectively * Program continues to diversify but still remains heavily concentrated with less than 5% of * By increasing the number of contributors in each settlement account and implementation of the new baseline methodology the performance of the program is expected to increase
Home Assistance Program		
21	Home Assistance Program	* Initiative was not evaluated in 2011 due to low uptake * Business Case assumptions were used to calculate savings
Pre-2011 Programs completed in 2011		

#	Initiative	OPA Province-Wide Key Evaluation Findings
22	Electricity Retrofit Incentive Program	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (multifamily buildings 99% realization rate and 62% net-to-gross ratio and C&I buildings 77% realization rate and 52% net-to-gross ratio)
23	High Performance New Construction	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings (realization rate of 100% and net-to-gross ratio of 50%)
24	Toronto Comprehensive	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
25	Multifamily Energy Efficiency Rebates	* Initiative was not evaluated * Net-to-Gross ratios used are consistent with the 2010 evaluation findings
26	Data Centre Incentive Program	* Initiative was not evaluated
27	EnWin Green Suites	* Initiative was not evaluated

Table 5: Summarized Program Results

Program	Gross Savings			Net Savings		Contribution to Targets	
	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)		Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	408	1,577,128		247	1,087,989	245	4,350,268
Business Program Total	288	1,072,480		249	872,353	199	3,364,639
Industrial Program Total	24	143,002		18	109,094	18	436,376
Home Assistance Program Total	0	0		0	0	0	0
Pre-2011 Programs completed in 2011 Total	29	169,523		15	88,043	15	352,173
Total OPA Contracted Province-Wide CDM Programs	**749**	**2,962,133**		**530**	**2,157,479**	**477**	**8,503,456**

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings		Contribution to Targets	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program											
1	Appliance Retirement	100%	100%	86	594,719	51%	52%	44	309,783	43	1,238,122
2	Appliance Exchange	100%	100%	3	3,820	52%	52%	1	1,969	1	7,198
3	HVAC Incentives	100%	100%	297	592,145	60%	60%	177	352,545	177	1,410,178
4	Conservation Instant Coupon Booklet	100%	100%	9	151,395	114%	111%	10	166,902	10	667,608
5	Bi-Annual Retailer Event	100%	100%	13	235,049	113%	110%	15	256,791	15	1,027,163
6	Retailer Co-op	-	-	0	0	-	-	0	0	0	0
7	Residential Demand Response	0%	0%	0	0	-	-	0	0	0	0
8	Residential New Construction	-	-	0	0	-	-	0	0	0	0
Business Program											
9	Efficiency: Equipment Replacement	93%	131%	177	754,011	74%	76%	130	576,642	130	2,306,568
10	Direct Install Lighting	108%	90%	111	318,469	93%	93%	119	295,711	68	1,058,072
11	Existing Building Commissioning Incentive	-	-	0	0	-	-	0	0	0	0
12	New Construction and Major Renovation Incentive	-	-	0	0	-	-	0	0	0	0
13	Energy Audit	-	-	0	0	-	-	0	0	0	0
14	Commercial Demand Response (part of the Residential program schedule)	0%	0%	0	0	-	-	0	0	0	0
15	Demand Response 3 (part of the Industrial program schedule)	76%	100%	0	0	n/a	n/a	0	0	0	0
Industrial Program											
16	Process & System Upgrades	-	-	0	0	-	-	0	0	0	0
17	Monitoring & Targeting	-	-	0	0	-	-	0	0	0	0
18	Energy Manager	-	-	0	0	-	-	0	0	0	0
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	94%	134%	24	143,002	74%	76%	18	109,094	18	436,376
20	Demand Response 3	84%	100%	0	0	n/a	n/a	0	0	0	0
Home Assistance Program											
21	Home Assistance Program	-	-	0	0	-	-	0	0	0	0
Pre-2011 Programs completed in 2011											
22	Electricity Retrofit Incentive Program	77%	77%	28	164,070	52%	52%	15	85,317	15	341,266
23	High Performance New Construction	100%	100%	1	5,453	50%	50%	1	2,727	1	10,906
24	Toronto Comprehensive	-	-	0	0	-	-	0	0	0	0
25	Multifamily Energy Efficiency Rebates	-	-	0	0	-	-	0	0	0	0
26	Data Centre Incentive Program	-	-	0	0	-	-	0	0	0	0
27	EnWin Green Suites	-	-	0	0	-	-	0	0	0	0

Assumes demand response resources have a persistence of 1 year

Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year. Please see methodology tab for more detailed information.

Yellow cells are intended for the LDC to input information to complete their OEB Reporting Template.

Table 6: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.53	0.53	0.53	0.48
2012				
2013				
2014				0.00
Verified Net Annual Peak Demand Savings Persisting in 2014:				0.48
nder Bay Hydro Electricity Distribution Inc. 2014 Annual CDM Capacity Target:				8.48
Verified Portion of Peak Demand Savings Target Achieved in 2014(%):				5.63%
LDC Milestone submitted for 2011				-%
Variance				

Table 7: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	2.16	2.16	2.16	2.03	8.50
2012					
2013					
2014					
Verified Net Cumulative Energy Savings 2011-2014:					8.50
Thunder Bay Hydro Electricity Distribution Inc. 2011-2014 Cumulative CDM Energy Target:					47.38
Verified Portion of Cumulative Energy Target Achieved (%):					17.95%
LDC Milestone submitted for 2011					-%
Variance					

Table P1: Province-Wide Participation

#	Initiative	Activity Unit	Uptake/ Participation Units
Consumer Program			
1	Appliance Retirement	Appliances	56,110
2	Appliance Exchange	Appliances	3,688
3	HVAC Incentives	Equipment	111,587
4	Conservation Instant Coupon Booklet	Products[4]	559,462
5	Bi-Annual Retailer Event	Products[5]	870,332
6	Retailer Co-op	Products	152
7	Residential Demand Response	Devices	19,577
8	Residential New Construction	Houses	7
Business Program			
9	Efficiency: Equipment Replacement	Projects	2,516
10	Direct Installed Lighting	Projects	20,297
11	Existing Building Commissioning Incentive	Buildings	-
12	New Construction and Major Renovation Incentive	Buildings	10
13	Energy Audit	Audits	103
14	Commercial Demand Response (part of the Residential program schedule)	Devices	264
15	Demand Response 3 (part of the Industrial program schedule)	Facilities	148
Industrial Program			
16	Process & System Upgrades[2]	Projects	-
17	Monitoring & Targeting[2]	Projects	-
18	Energy Manager[2 3]	Managers	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)[1]	Projects	433
20	Demand Response 3	Facilities	134
Home Assistance Program			
21	Home Assistance Program	Homes	46
Pre 2011 Programs Completed in 2011			
22	Electricity Retrofit Incentive Program	Projects	2,023
23	High Performance New Construction	Projects	145
24	Toronto Comprehensive	Projects	553
25	Multifamily Energy Efficiency Rebates	Projects	110
26	Data Centre Incentive Program	Projects	5
27	EnWin Green Suites	Projects	3

[2] *Results are based on completed incentive projects (see "Methodology" tab for more information)*

[3] *Includes: Roving Energy Managers, Key Account Managers and Embedded Energy Managers with completed projects*

[4] *209,693 valid coupons redeemed*

[5] *369,446 valid coupons redeemed*

Table P2: Province-Wide Results

Program	Gross Savings			Net Savings	
	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)		Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program Total	73,757	192,379,633		49,123	133,519,668
Business Program Total	78,048	251,304,448		64,594	198,124,227
Industrial Program Total	68,648	41,493,145		57,099	31,947,577
Home Assistance Program Total	4	56,119		2	39,283
Pre-2011 Programs completed in 2011 Total	87,169	460,822,079		44,833	241,853,020
Total OPA Contracted Province-Wide CDM Programs	**307,626**	**946,055,425**		**215,651**	**605,483,775**

#	Initiative	Realization Rate		Gross Savings		Net-to-Gross Ratio		Net Savings	
		Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)	Peak Demand Savings	Energy Savings	Incremental Peak Demand Savings (kW)	Incremental Energy Savings (kWh)
Consumer Program									
1	Appliance Retirement	100%	100%	6,750	45,971,627	51%	51%	3,299	23,005,812
2	Appliance Exchange	100%	100%	719	873,531	51%	51%	371	450,187
3	HVAC Incentives	100%	100%	53,209	99,413,430	60%	60%	32,037	59,437,670
4	Conservation Instant Coupon Booklet	100%	100%	1,184	19,192,453	114%	111%	1,344	21,211,537
5	Bi-Annual Retailer Event	100%	100%	1,504	26,899,265	112%	110%	1,681	29,387,468
6	Retailer Co-op	100%	100%	0.18	3,917	68%	68%	0	2,652
7	Residential Demand Response	n/a	n/a	10,390	23,597	n/a	n/a	10,390	23,597
8	Residential New Construction	100%	100%	0	1,813	41%	41%	0	743
Business Program									
9	Efficiency: Equipment Replacement	106%	91%	34,201	184,070,265	72%	74%	24,467	136,002,258
10	Direct Installed Lighting	108%	93%	22,155	65,777,197	108%	93%	23,724	61,076,701
11	Existing Building Commissioning Incentive	-	-	-	-	-	-	-	-
12	New Construction and Major Renovation Incentive	50%	50%	247	823,434	50%	50%	123	411,717
13	Energy Audit	-	-	-	-	-	-	-	-
14	Commercial Demand Response (part of the Residential program schedule)	n/a	n/a	55	131	n/a	n/a	55	131
15	Demand Response 3 (part of the Industrial program schedule)	76%	n/a	21,390	633,421	n/a	n/a	16,224	633,421
Industrial Program									
16	Process & System Upgrades	-	-	-	-	-	-	-	-
17	Monitoring & Targeting	-	-	-	-	-	-	-	-
18	Energy Manager	-	-	-	-	-	-	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	111%	91%	6,372	38,412,408	72%	75%	4,615	28,866,840
20	Demand Response 3	84%	n/a	62,276	3,080,737	n/a	n/a	52,484	3,080,737
Home Assistance Program									
21	Home Assistance Program	100%	100%	4	56,119	70%	70%	2	39,283
Pre-2011 Programs completed in 2011									
22	Electricity Retrofit Incentive Program	80%	80%	40,418	223,956,390	54%	54%	21,550	120,492,549
23	High Performance New Construction	100%	100%	10,197	52,371,183	49%	49%	5,098	26,185,591
24	Toronto Comprehensive	113%	113%	33,467	174,070,574	50%	52%	15,805	86,964,886
25	Multifamily Energy Efficiency Rebates	93%	93%	2,553	9,774,792	78%	78%	1,981	7,595,683
26	Data Centre Incentive Program	100%	100%	81	533,038	100%	100%	81	533,038
27	EnWin Green Suites	100%	100%	453	116,102	70%	70%	317	81,272

Assumes demand response resources have a persistence of 1 year

Program	Contribution to Targets	
	Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program Total	38,405	534,017,835
Business Program Total	41,048	767,657,790
Industrial Program Total	4,613	118,543,019
Home Assistance Program Total	2	157,134
Pre-2011 Programs completed in 2011 Total	44,833	967,412,079
Total OPA Contracted Province-Wide CDM Programs	**128,901**	**2,387,787,856**

#	Initiative	Contribution to Targets	
		Program-to-Date: Net Annual Peak Demand Savings (kW) in 2014	Program-to-Date: 2011-2014 Net Cumulative Energy Savings (kWh)
Consumer Program			
1	Appliance Retirement	3,160	91,903,303
2	Appliance Exchange	181	1,930,651
3	HVAC Incentives	32,037	237,750,681
4	Conservation Instant Coupon Booklet	1,344	84,846,148
5	Bi-Annual Retailer Event	1,681	117,549,874
6	Retailer Co-op	0	10,607
7	Residential Demand Response	0	23,597
8	Residential New Construction	0	2,973
Business Program			
9	Efficiency: Equipment Replacement	24,438	543,856,392
10	Direct Installed Lighting	16,486	221,520,977
11	Existing Building Commissioning Incentive	-	-
12	New Construction and Major Renovation Incentive	123	1,646,869
13	Energy Audit	-	-
14	Commercial Demand Response (part of the Residential program schedule)	0	131
15	Demand Response 3 (part of the Industrial program schedule)	0	633,421
Industrial Program			
16	Process & System Upgrades	-	-
17	Monitoring & Targeting	-	-
18	Energy Manager	-	-
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	4,613	115,462,282
20	Demand Response 3	0	3,080,737
Home Assistance Program			
21	Home Assistance Program	2	157,134
Pre-2011 Programs completed in 2011			
22	Electricity Retrofit Incentive Program	21,550	481,970,197
23	High Performance New Construction	5,098	104,742,366
24	Toronto Comprehensive	15,805	347,859,545
25	Multifamily Energy Efficiency Rebates	1,981	30,382,733
26	Data Centre Incentive Program	81	2,132,152
27	EnWin Green Suites	317	325,086

Assumes demand response resources have a persistence of 1 year

Summary - Provincial Progress

Table P3: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	215.7	136.4	135.7	128.9
2012				
2013				
2014				
Verified Net Annual Peak Demand Savings in 2014:				**128.9**
2014 Annual CDM Capacity Target				**1,330**
Verified Peak Demand Savings Target Achieved - 2011 (%):				**9.69%**

Table P4: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	605.5	601.6	599.6	580.9	2,388
2012					0
2013					0
2014					0
Verified Net Cumulative Energy Savings 2011-2014:					**2,388**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Energy Target Achieved - 2011 (%):					**39.79%**

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Initiative was not evaluated in 2011, reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
		Additional Note: project counts were derived by filtering out "Application Status" = "Post-Project Submission - Payment denied by LDC" and only including projects with an "Actual Project Completion Date" in 2011 and pulling both the "Application Name" field followed by the "Building Address 1" field from the Post Stage Retrofit Report and finally performing a count of the Building Addresses.		
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions (as per evaluated results in 2010 and consultation with OPA-LDC Work Groups)	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	No resource savings results determined in 2011; Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Pre-2011 Programs completed in 2011				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011, assumptions as per 2010 evaluation		

ERII Sector (C&I vs. Industrial Mapping)	
Building Type	**Sector**
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Office,Warehouse	C&I

Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I
Restaurant - Quick Serve	C&I

Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%
Hydro Ottawa Limited	5.6%

Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Exhibit	Tab	Schedule	Appendix	Contents
4 – Operating Costs				
	1			**Overview**
		1		Manager's Summary of Operating Costs
	2			**OM&A Costs**
		1		Departmental and Corporate OM&A Activities
		2		OM&A Detailed Costs Tables
		3		Variance Analysis on OM&A Costs
		4		Employee Compensation, Incentive Plan Expenses, Pension Expense and Post-Retirement Benefits
		5		Shared Service & Corporate Cost Allocation
		6		Purchase of Products and Services from Non-Affiliates
		7		Depreciation, Amortization and Depletion
		8		Asset Retirement Obligations
	3			**Income Tax, Large Corporation Tax**
		1		Tax Calculations
		2		Capital Cost Allowance (CCA)
	4			**Modified CGAAP Reconciliation**
		1		MCGAAP Impact on OM&A
		2		MCGAAP Impact on Depreciation
		3		MCGAAP Impact on Taxes
	5			Green Energy Act Plan
	6			Conservation and Demand Management (CDM) Costs
			4-A	Affiliate Services Agreement
			4-B	Procurement Policy
			4-C	Post-Retirement Benefit Report
			4-D	2011 Federal & Ontario Tax Return
			4-E	2009 – 2011 Notice of Assessments

OVERVIEW

MANAGER'S SUMMARY OF OPERATING COSTS

The operating costs presented in this Exhibit represent the annual expenditures required to sustain Thunder Bay Hydro's distribution operations. Thunder Bay Hydro follows the OEB's Accounting Procedures Handbook (the "APH") in distinguishing work performed between operations and maintenance. Historically Thunder Bay Hydro has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its financial statements. As stated throughout this application, given the recent announcement by the Canadian Accounting Standards Board (AcSB) "In anticipation of future activities of the International Accounting Standards Board, the Canadian Accounting Standards Board decided at its September 2012 meeting to extend the deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities to 1 January 2014", Thunder Bay Hydro will be deferring the changeover date to International Financial Reporting Standards (IFRS) to January 1, 2014. As such, Thunder Bay Hydro`s transition date is January 1, 2013. Therefore this application has been prepared using what has been termed "modified CGAAP" (MCGAAP). The actuals for 2009 through to the Bridge Year 2012 have been prepared using CGAAP as historically done and the Test Year 2013 has been prepared using both CGAAP and MCGAAP. These modifications include updating the capitalization and depreciation policy to align with IFRS. A full explanation of the impact of the changes in the 2013 Test Year resulting from the changes in Thunder Bay Hydro's capitalization and depreciation policy can be found in Exhibit 2, Tab 5.

Thunder Bay Hydro has included one-time costs in the 2013 Test Year as follows:

- External incremental costs relating to the 2013 Cost of Service Rate Application process. Projected are total incremental costs of $136,000 and included is $34,000 (25%) in the 2013 Test Year.

- Deemed interest on long-term debt has been adjusted to reflect the four year average of the expected interest costs over the period January 1, 2013 to December 31, 2016. Thunder Bay Hydro's anticipated interest on long-term debt over the period 2013-2016 is projected to be $4,006,340. This number annualized over the four years is $1,001,585. See Exhibit 5 for full discussion of the "annualized debt".

- Security audit related costs related to our smart meter infrastructure are estimated at $30,000 over the Test Year and IRM periods and as such Thunder Bay Hydro has included $7,500 in the 2013 Test Year.

- Thunder Bay Hydro has safety related purchases that do not occur annually. The corporation's funding of the fire retardant clothing is a significant cost to the corporation every other year. The Test Year reflects $45,000 which is the four year average cost.

- Finally, the 2013 Test Year will have a one-time building demolition cost. Thunder Bay Hydro has reduced the anticipated costs to $15,000 to recognize 25% of the net incremental cost in the 2013 Test Year.

Thunder Bay Hydro has removed the non-regulatory expenses in the 2009 – 2011 historical actuals, the 2012 Bridge year and 2013 Test year.

Thunder Bay Hydro's audited financial statements for the years 2009, 2010 and 2011 included charitable contributions and fees paid to various charitable organizations as outlined below in Table 4-1.1. The 2013 Test year only includes LEAP expenses.

Table 4-1.1 - Summary of Donations

	Charitable	Political	LEAP	Total
2009	$23,196	$450		$23,646
2010	$26,007	$1,600		$27,607
2011	$18,656		$22,000	$40,656
2012			$16,500	$16,500
2013	$0	$0	$24,200	$24,200

Included in the 2009 – 2011 Historical Actuals and the 2012 Bridge year are one-time costs as follows:

- The 2012 Bridge year includes $33,100 for external incremental costs relating to the 2013 Cost of Service Rate Application process.

- The 2012 Bridge year also includes $23,520 for external incremental costs relating to Thunder Bay Hydro`s Motion to Vary EB-2011-0197.

- Thunder Bay Hydro received one-time comprehensive liability premium reductions of $34,788 and $33,552 in 2010 and 2012 respectively. In 2012 Thunder Bay Hydro added privacy liability and network security coverage for an additional $13,659 (this increase is not one-time).

- The 2009 Actuals includes $32,621 for external incremental costs relating to the 2009 Cost of Service Rate Application process.

- The 2011 Actuals reflects $65,000 for safety related purchases that do not occur annually.

- One-time Special Purpose charge of $224,892 and $164,327 are reflected in the 2010 and 2011 Actuals respectively.

- One-time bad debt expense for the Class Action Settlement of $161,043 in 2010 Actuals.

- Sub-Station Demolition costs of $65,000, $10,000 and $53,800, are included in the 2009 and 2011 Actuals and the 2012 Bridge year respectively.

- Thunder Bay Hydro has not included legal professional fees as “one-time” given that the very nature of such costs usually are for unique situations; however, such are expected to occur regularly.

The following is a summary of Thunder Bay Hydro`s Recoverable OM&A variances for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and the 2013 Test Year (MCGAAP) as required by the Filing Requirements and provided in Tables 4.1.2. Table 4.1.3 provides the OM&A expenses variances for 2009 through 2013 all on a CGAAP basis.

Table 4-1.2 – Summary of OM&A Expenses

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MCGAAP**
Operations	2,789,357	2,703,387	2,866,616	3,184,794	3,057,560	3,319,533	3,559,704
Maintenance	3,049,733	3,177,750	3,300,110	2,786,514	3,885,577	3,109,691	3,951,962
SubTotal	**5,839,091**	**5,881,137**	**6,166,726**	**5,971,308**	**6,943,137**	**6,429,224**	**7,511,666**
%Change (year over year)			4.9%	(3.2%)	16.3%	(7.4%)	16.8%
%Change (Test Year vs Last Rebasing Year - Actual)						9.3%	21.8%
Billing and Collecting	2,244,506	1,996,320	2,067,993	1,945,612	2,197,135	2,132,818	2,134,694
Community Relations	228,339	266,913	294,767	197,363	229,274	262,133	262,133
Administrative and General	3,623,127	3,820,604	3,928,036	3,986,493	4,415,917	4,593,820	4,773,922
SubTotal	**6,095,972**	**6,083,836**	**6,290,796**	**6,129,468**	**6,842,327**	**6,988,771**	**7,170,749**
%Change (year over year)			3.4%	(2.6%)	11.6%	2.1%	2.6%
%Change (Test Year vs Last Rebasing Year - Actual)						14.9%	14.0%
Total	**11,935,063**	**11,964,973**	**12,457,522**	**12,100,776**	**13,785,463**	**13,417,995**	**14,682,415**
%Change (year over year)			4.1%	(2.9%)	13.9%	(2.7%)	9.4%

Thunder Bay Hydro is proposing recovery of 2013 Test Year OM&A costs, excluding amortization, PILs and Interest totaling $14,418,846.

Table 4-1.3 – OM&A Expense Variances

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	Variance 2009 BA – 2009 Actuals	2010 Actuals	Variance 2010 Actuals vs. 2009 Actuals	2011 Actuals	Variance 2011 Actuals vs. 2010 Actuals	2012 Bridge Year	Variance 2012 Bridge vs. 2011 Actuals	2013 Test Year (CGAAP)	Variance 2013 Test vs. 2012 Bridge
Operations	2,789,357	2,703,387	85,970	2,866,616	163,229	3,184,794	318,178	3,057,560	(127,234)	3,319,533	261,973
Maintenance	3,049,733	3,177,750	(128,017)	3,300,110	122,360	2,786,514	(513,595)	3,885,577	1,099,063	3,109,691	(775,886)
Billing and Collecting	2,244,506	1,996,320	248,186	2,067,993	71,674	1,945,612	(122,381)	2,197,135	251,523	2,132,818	(64,317)
Community Relations	228,339	266,913	(38,574)	294,767	27,854	197,363	(97,403)	229,274	31,911	262,133	32,859
Administrative and General	3,623,127	3,820,604	(197,477)	3,928,036	107,432	3,986,493	58,456	4,415,917	429,425	4,593,820	177,903
Total OM&A Expenses	$ 11,935,063	11,964,973	(29,910)	12,457,522	492,549	12,100,776	(356,746)	13,785,463	1,684,687	$ 13,417,995	(367,469)
Variance from previous year				492,549		(356,746)		1,684,687		(367,469)	
Percent change (year over year)				4.1%		(2.9%)		14%		(2.7%)	
Percent Change: Test year vs. Most Current Actual						10.89%					
Simple average of % variance for all years						12.14%					3%
Compound Annual Growth Rate for all years											2.9%
Compound Growth Rate (2011 Actuals vs. 2009 Actuals)						1.14%					

Table 4-1.4 below sets out the OM&A cost per customer and Full Time equivalent employees.

Table 4-1.4 -OM&A Per Customer and per FTE

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MCGAAP
Number of Customers	49,631	49,439	49,599	49,796	49,905	50,015	50,015
Total Recoverable OM&A from Appendix 2-I	$ 11,935,063	$ 11,964,973	$ 12,457,522	$ 12,100,776	$ 13,785,463	$ 13,417,995	$ 14,682,415
OM&A cost per customer	$ 240.48	$ 242.02	$ 251.17	$ 243.01	$ 276.23	$ 268.28	$ 293.56
Number of FTEEs	138.25	127.8834709	130.1646185	132.81	136.58	137.81	137.81
Customers/FTEEs	358.99	386.59	381.05	374.94	365.39	362.93	362.93
OM&A Cost per FTEE	86,329.57	93,561.53	95,705.90	91,113.44	100,933.25	97,365.90	106,541.00

The number of customers include the annual average number of residential, GS<50 and GS>50 customers as found in Thunder Bay Hydro's Load Forecast (metered customers).

Detailed information with respect to OM&A costs, arranged by USoA account, is provided in Exhibit 4, Tab 2, Schedule 2. Detailed information with respect to OM&A variances, arranged by USoA account, is provided in Exhibit 4, Tab 2, Schedule 3.

The variance used to determine the OM&A accounts requiring analysis has been prescribed by the Filing Requirements as 0.5% of distribution revenue for distributor's with distribution revenue exceeding $10 million.

Table 4-1.5 - Materiality Threshold

	2009 Board-Approved	2009 Actual	2010 Actual	2011 Actual
Distribution Revenue Requirement	$17,105,956	$16,779,398	$16,504,064	$17,395,065
0.50%	$85,530	$83,897	$82,520	$86,975
			Average	$84,731

The average materiality threshold between the 2009 Board Approved and 2009 to 2011 Actuals is $84,731, thus, Thunder Bay Hydro has used $85,000 as the threshold for its variance analyses.

OM&A Costs

OM&A costs in this Exhibit represent Thunder Bay Hydro's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels. OM&A costs also include providing services to customers connected to Thunder Bay Hydro's distribution system, and meeting the requirements of the OEB's Standard Supply Service Code and Retail Settlement Code.

The proposed OM&A cost expenditures for the 2013 Test Year are the result of a business planning and work prioritization process that ensures that the most appropriate, cost effective solutions are put in place.

OM&A Budgeting Process:

The operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared before the start of each fiscal year. Once approved, the budget provides a plan against which actual results are evaluated. The 2013 budget has been approved by the Board of Directors on September 20th, 2012.

The operating budget is a component of the overall budget process described in Exhibit 1, Tab 2, Schedule 2.

Operating Work Plans:

Each Division Vice President ("VP") is responsible for the preparation of the divisional budget. The following directives are provided to each VP:

- Outside expenses for all department budgets are built using previous year actual, current year forecast and current year budget as the base;
- Significant variances in spending from prior years must be explained and documented;
- Review the head count of the department for accuracy and outline any changes;

- Accounting prepares a total labour, overtime and benefit budget by department using the labour resource budget as provided by the respective VPs or the President as applicable.

Income Tax, Large Corporation Tax and Ontario Capital Taxes:

Thunder Bay Hydro is subject to the payment of PILs under Section 93 of the *Electricity Act, 1998*, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the *Income Tax Act (Canada)* and the Ontario *Corporations Tax Act*. Please refer to Exhibit 4, Tab 3, Schedule 1 and Appendix 4-D for further tax calculations and a copy of the 2011 Federal tax return.

Regulatory Costs:

Regulatory costs as indicated in the variance analysis are presented in Table 4-2.1. Regulatory costs for the 2013 rate application (amounting to $34,000), include Thunder Bay Hydro's annualization of the one-time external consulting costs as well as anticipated Board and Intervenors expenses relating to the 2013 Cost of Service rate application process (Table 4-2.2 below). The Cost of Service rate application costs have been spread over a four year period beginning with the 2013 OM&A budget (in other words, 25% of actual total costs have been included in the 2013 Test Year).

Table 4-2.1 - Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year (CGAAP) and (MCGAAP)	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	126,527	119,343	117,100	(1.88%)	120,000	2.48%
2	OEB Section 30 Costs (Applicant-originated)									
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going		4,334	5,000	15.36%	5,000	0.00%
4	Expert Witness costs for regulatory matters	5655		On-Time					2,750	
5	Legal costs for regulatory matters	5655		On-Time					11,250	
6	Consultants' costs for regulatory matters	5655		On-Time	-		56,620		8,750	(84.55%)
7	Operating expenses associated with staff resources allocated to regulatory matters									
8	Operating expenses associated with other resources allocated to regulatory matters - Board Costs 2013 COS	5655		On-Time					2,500	
9	Other regulatory agency fees or assessments	5655		On-Going	21,420	20,503	19,570	-4.55%	20,300	3.73%
10	Any other costs for regulatory matters (Notice of Application - Newspaper Advertisement Costs)	5655		On-Going	-	1,512	1,550	2.51%	2,000	29.03%
11	Intervenor costs	5655		On-Time	9,523	261	2,500	856.13%	8,750	250.00%
12	Sub-total - Ongoing Costs [3]		$ -		147,947	145,693	143,220	(1.70%)	147,300	2.85%
13	Sub-total - One-time Costs [4]		$ -		9,523	261	59,120	22510.62%	34,000	(42.49%)
14	Total		$ -		157,470	145,954	202,340	38.63%	181,300	(10.40%)

Table 4-2.2 - One-Time Costs Associated with the 2013 Cost of Service Rate Application

	Historical Year(s)	2012 Bridge Year	2013 Test Year (CGAAP) and (MCGAAP)	Annualized 2013 Test Year
Expert Witness costs for regulatory matters	$ -	$ -	$ 11,000	$ 2,750
Legal costs for regulatory matters	$ -	$ -	$ 45,000	$ 11,250
Consultants' costs for regulatory matters	$ -	$ 56,620	$ 35,000	$ 8,750
Operating expenses associated with staff resources allocated to regulatory matters	$ -	$ -	$ -	$ -
Operating expenses associated with other resources allocated to regulatory matters [1]	$ -	$ -	$ 10,000	$ 2,500
Intervenor costs		$ 2,500	$ 35,000	$ 8,750

Low Income Assistance Program (LEAP)

Thunder Bay Hydro has included $24,200 of expense for the Low Income Assistance Program (LEAP) under Community Relations. This amount is based on 0.12% of the 2013 Test Year Revenue Requirement, rounded.

Charitable Contributions

Thunder Bay Hydro has not included any other charitable donations in OM&A expenses for 2013.

Inflation in 2012 Bridge and 2013 Test Year

The 2012 Bridge Year forecast is based on actual expenses as of June 30, 2012 plus expected expenditures for the remaining 6 months. No inflation has been applied to the expected expenditures except in cases where it is a known amount, such as an increase to wages for union staff according to the collective agreement. In the 2013 Test Year expenses have been budgeted based on existing prices and increases if known. A basic inflation rate has not been applied to all accounts.

DEPARTMENTAL AND CORPORATE OM&A ACTIVITIES

Maintenance Plan Overview

The expenses for this department include all costs relating to the operation (5005-5096) and maintenance (5105-5195) of Thunder Bay Hydro's electrical system. This includes both direct labour costs and non-capital material spending to support both scheduled and reactive maintenance events. In addition, costs are allocated from support departments to cover the costs of Labour Burden, Engineering, and Stores. Thunder Bay Hydro's maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through an effective planned maintenance program, including predictive and preventative actions.

Thunder Bay Hydro's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with Thunder Bay Hydro's capital project work so that where maintenance programs identified matters which require capital investments, Thunder Bay Hydro may adjust its capital spending priorities to address those matters.

The foundation of the maintenance program at Thunder Bay Hydro is to maintain its assets for the lowest possible life cycle cost while focusing on the following strategic objectives:

- Addressing any health & safety issues;
- Addressing any environmental risks;
- Regulatory compliance obligations;
- Ensuring equipment reliability.

Three types of maintenance programs are widely used in industry and all others are variants of these three, namely reactive, preventative, and predictive maintenance.

Reactive maintenance, as its name suggests, is solely reactive to failures or defects with only inspections or some basic tests being performed to determine whether the equipment is functioning as expected. This type of maintenance is most effective for low cost equipment where maintenance can be a significant portion of the replacement cost and the equipment is

not critical should it fail. An example of this would be how we maintain lightning arrestors, cut-outs, insulators, and other line hardware.

Preventative maintenance, also as its name suggests, is an attempt to perform maintenance in fixed cycles based on industry knowledge of what period is anticipated to be optimal in terms of maintenance costs and failure costs. Preventative maintenance is more extensive than reactive and could include such activities as greasing breakers or switches annually to overhauling a recloser at a fixed number of operations. This type of maintenance is most effective for mid to high cost equipment where preventative maintenance is a good investment towards preventing a catastrophic failure. This type of maintenance is widely used where failure of equipment can be critical to the operation or where the cost of an unscheduled replacement significantly exceeds the cost of a scheduled replacement.

Predictive maintenance, again as its name suggests, is a methodology that attempts to anticipate when a failure will occur and schedule maintenance prior to the impending failure. This is the newest of the maintenance methodologies, which attempts to reduce maintenance costs by extending the maintenance period beyond that of preventative maintenance. This type of maintenance also attempts to detect imminent failures that would have occurred under the preventative maintenance approach. Predictive maintenance is most effective for very high cost equipment or equipment which is very critical, and failures cannot be managed effectively. An example for a substation transformer would be the use of dissolved gas analysis, furan analysis, and doable testing to determine when it would be optimal to overhaul a substation transformer rather than perform the overhaul at a fixed period. Of course this is not a perfect science and failures do occur even with some of the most sophisticated testing and monitoring equipment available.

Thunder Bay Hydro’s maintenance program will utilize all of the above types of maintenance approaches on a best fit to the equipment basis. This is best described as Reliability Centered Maintenance (RCM). RCM is characterized by determining what type of maintenance is appropriate, based on failure mechanisms and consequences. It is particularly suited to complex plants where there are many failure modes.

In Thunder Bay Hydro's case, low cost and low criticality equipment like lightning arrestors, distribution poles, fuse cut-outs, distribution transformers, low priority cables, and line hardware will be reactively maintained. Mid-cost and mid-criticality equipment like breakers, reclosers, line switches, relays, high priority cables, and most substation equipment will be maintained with the preventative methodology. Thunder Bay Hydro's most expensive and critical assets, which are its substation transformers, will be maintained with the predictive methodology. This approach also utilizes principles from reliability centered maintenance where the equipment's required availability, as well as maintenance costs, is considered in the program development.

Thunder Bay Hydro's maintenance activities are functionally organized such that on a periodic basis the inspection and detection of deficiencies/defects, as well as any minor maintenance functions, will be performed. Periodic maintenance can be further broken down into two separate components.

Firstly, "Patrolling & Visual Inspections" where in Lines this is accomplished with the detailed risk assessments and a thermo graphic survey completed at each location every three years. In Stations, each location is inspected monthly and a thermo graphic survey is conducted annually. Additionally, in Stations, a detailed risk assessment is conducted every three years.

Secondly, "Work & Test" maintenance is performed periodically where a piece of equipment is test operated to verify proper operation. Additionally, equipment that requires calibration is re-verified and/or any required testing is performed for predictive purposes, i.e. doable testing, furan analysis, etc. In Lines, equipment like reclosers and switches are test operated and lubricated every three years, and reclosers verified every six years. In the Stations, transformers will receive dissolved gas in oil analysis along with other diagnostic testing annually. Breakers will be test operated/lubricated and relays re-calibrated/verified every three years.

Corrective maintenance occurs only when the periodic maintenance activity has discovered a deficiency or defect. At that time, some corrective maintenance is scheduled like a part replacement, rebuild, or overhaul as deemed necessary to correct the problem discovered.

Thunder Bay Hydro is in the midst of implementing its maintenance program within its enterprise system where all periodic maintenance will be automatically generated. Additionally, corrective maintenance and failures will be traced to various equipment types, as well as each specific piece of equipment. As discussed in rate filing EB-2008-02451, Thunder Bay Hydro conducted a complete risk assessment for all overhead lines, underground equipment, cables, and substations. This system-wide inspection included a primarily visual inspection of all Thunder Bay Hydro's utility poles and associated components. Since the 2008 inspection, Thunder Bay Hydro has been methodically narrowing the scope of the inspection in order to inspect each asset with greater scrutiny, while still canvassing the entire system in the period legislated within Appendix C of the Distribution System Code. Thunder Bay Hydro's asset maintenance activities are exhaustive and well established practices. The execution of these activities are typically monitored and reported on by the appropriate supervisor. As maintenance demands caused by an increasingly ageing distribution network escalate, it is essential that the tracking, deployment, and prioritization of these activities become further centralized in an effort to closely monitor their influence on asset health and related performance indices.

The overall implementation plan for the maintenance program is to be as follows:

1. List all asset types;
2. Determine criticality and failure modes for each type;
3. Determine required reliability for each type;
4. Determine best or best combination of maintenance methods for each type;
5. Estimate required maintenance to achieve desired reliability for each type;
6. Estimate total maintenance cost for each type;
7. List each asset that will require maintenance;
8. Determine the total cost to maintain the distribution system;
9. Adjust the program or resources as required to match; and
10. Schedule start dates per priorities & last maintained.

Thunder Bay Hydro's Maintenance Program Strategy will be as follows:

1. Risk assessments will be performed on all assets every three years;

2. Infrared scans of all station assets to be performed annually and line assets to be performed every three years;
3. Low criticality equipment like line hardware, distribution transformers, and cables will be maintained only with objective evidence of defect or failure;
4. Breakers, reclosers, line switches, relays, and most substation equipment will be periodically maintained with a work and test procedure;
5. The most costly and critical assets; power transformers maintained with a predictive methodology, i.e. gas-in-oil, furan, doable testing, as well as some periodic maintenance; and
6. A spare power transformer is to be secured for each unique transformer type.

BUSINESS APPLICATIONS:

The Information Systems Department (ISD) personnel oversee the acquisition, installation, operation, maintenance, availability and security of the Thunder Bay Hydro's computer hardware, software, data and network resources. They provide support services to all departments for resources under the ISD scope of responsibility. ISD operates following generally accepted Information Technology industry standards. ISD is currently supporting over 200 users utilizing pc workstations, thin-clients, laptops and wireless devices to connect to the network resources. The ISD group actively pursues implementation of new technologies and services to support the Thunder Bay Hydro moving forward.

Software:

Supporting of computer operating systems, business applications, industry specific packages, design and geographic applications and standard integrated office products (deployment, installation, version upgrades, licensing, and maintenance).

Customized departmental and Thunder Bay Hydro applications are developed, tested, implemented and supported using standard development tools.

Maintain and update current levels of virus protection, security software updates and email filtering for security/virus risks.

Direct and coordinate out of scope/expertise development to third party vendors.

Data Management:

Maintain daily, weekly, and monthly data archives utilizing tape backup and other media for servers and other critical applications (offsite storage for disaster recovery).

Ensure the integrity and security of the data by following industry standards and implementing legislated privacy regulation controls (user/user group data access restrictions).

Help Desk and Training:

Providing basic, intermediate and advanced levels of on-site support and trouble-shooting to end users for any software, hardware and network resource connectivity issues under the ISD scope of responsibility.

Train employees on computer basics helping them to utilize the tools they have available through their office productivity software and customized in-house developed applications.

Cross training and knowledge transfer among ISD personnel to facilitate broad range support.

Research and Development:

Maintain a functional understanding of developments within the Information Technology industry and current trends in the Thunder Bay Hydro's operating environment.

Attend training and education forums in new technology and evaluate new products and services for Thunder Bay Hydro compatibility.

Plan to implement new technologies to ensure cost effective solutions are leveraged to support the corporate objectives.

Procurement/Disposal:

Responsible for setting standards, selecting specific products, detailing requisition specifications, engaging third party vendors, license management, maintenance contract management and invoice reconciliation for all technology purchase related activities within the Thunder Bay Hydro.

Lifecycle tracking of assets to determine their end of life disposal.

Customer Service

The Customer Service & Conservation Division has 4 distinct areas.

- The first is Customer Service which handles customer phone calls and walk in traffic. The staff in this area set up new accounts, liaise with the Electrical Safety Authority ("ESA") regarding electrical inspections, make account changes, handle customer moves, help customers manage arrears, collect on overdue accounts and answer questions related to billing, Time-of-Use ("TOU") rates and electricity conservation.
- The second area is Billing and Settlements where all aspects of customer billings are handled. This includes
    - Rate setups, bill design and bill production for both load and generation customers;
    - Retailer interactions for customer bills including settlement processes between Thunder Bay Hydro and the individual retailers; and
    - Management of third party contracts related to legacy meter reading and bill printing.

  Ultimately this group ensures sufficient business processes are in place from the reading of meters to the final delivery of bills.

- The third area is Advanced Metering Infrastructure ("AMI") where the main responsibility is placed for ensuring the various smart metering systems are integrated and synchronized for proper meter reading and billing data flow for the Billing and Settlements group. One major task is the monitoring of the AMI communications network for reliability, stability and security. This area also ensures proper data flows for

other meter reading related systems for mid and large commercial and industrial customers is functioning properly. Finally, this area provides expertise and support to Customer Service on the TOU web presentment portal for customers.

- The fourth area is Conservation and Energy Services. This area is responsible for the delivery and management of conservation and demand management programs along with the general responsibility of responding to customer requests for site visits as it relates to energy usage in their places of residence or business.

Public Relations

The Communications and Events Coordinator is responsible for external communications to stakeholders and the community as well as the provision of internal communication for the organization's staff. The position administers the development and execution of the Thunder Bay Hydro's communication strategy.

The realm of responsibility externally includes media relations and marketing conservation initiatives, customer education about electricity-related issues and access to programs, community outreach for safety and conservation-related topics, as well as support for, and organizing cooperation with other organizations who share similar goals. Internally, the position provides consultation for risk management issues, helps plan and implement Human Resources strategies, produces staff communications, and coordinates events focused on corporate responsibility.

The position is also responsible for the evolution and maintenance of Thunder Bay Hydro's website. The site features both informative and interactive modules that are kept current through in-house administration. Web content supports customer relations and education, automates administrative tasks for customers and contractors, and features current information on public announcements, conservation and safety programs and media releases.

Engineering Department

Engineering delivers drafting services from the design technicians for capital projects and provides distribution system asset information to many departments within Thunder Bay Hydro. Engineering costs are allocated to operations, maintenance, capital, and Third Party receivable accounts based on total labour and sub-contracting costs. A standard overhead percentage is set at the beginning of the year for all jobs, adjusted as required throughout the year and adjusted to actual at year end.

Stores/Warehouse

Stores area is accountable for managing the control, and movement of materials for Thunder Bay Hydro. This includes monitoring inventory levels, issuing material receipts, material issues, and material returns as required. The cost of the stores department is allocated to all departmental, capital and Third Party receivable accounts as an overhead cost based on direct material costs. A standard overhead percentage is set at the beginning of the year for all jobs, adjusted as required throughout the year and adjusted to actual at year end.

Garage/Transportation Fleet

This area assists with the maintenance and control of approximately 60 fleet vehicles. Its objectives include keeping maintenance schedules to ensure vehicle reliability and safety, and the minimization of vehicle downtime. Vehicle costs are allocated to operations, maintenance, capital and Third Party receivable accounts based on use. A standard “cost per hour” is set for each vehicle within the fleet. Costs are adjusted to actual at year end.

Safety and Health

The Health and Safety function exists at Thunder Bay Hydro to implement and maintain a Safety Management System that facilitates the achievement of the Thunder Bay Hydro’s first priority, which is to secure the Health and Safety of our employees and the public.

Part of the success of our Safety Management System is due to our commitment to creating and maintaining a corporate culture where Health and Safety is the top priority for all employees

at all levels. To date, this has been achieved through the implementation of "Target Zero" which is what we have internally branded as our Safety Management System. Target Zero has been an unqualified success for Thunder Bay Hydro since its introduction and we have supported this program by ensuring awareness and competency regarding safe work practices in everything we do.

Health and Safety Objectives and Strategies

The ultimate objective of our Health and Safety efforts is the pursuit of zero workplace incidents.

Long term goals to support this objective are:

- Zero lost time workplace incidents and an incidents performance trend which compares favourably with industry benchmarks.
- Maintaining the momentum of Target Zero and ensuring that the program remains fresh and its profile high within Thunder Bay Hydro.
- Maintaining a corporate culture where safety is of primary importance in decision making.
- Delivering programs to increase safety awareness at work and at home, and to promote employee wellness.
- Delivering a strong public safety program.

Short term goals to support this objective are:

- Update the corporations Hazard Identification and Risk Assessment
- Conduct a gap analysis for preventative measures and put an action plan in place to ensure that preventative measures are either updated or implemented
- Develop written work procedures and update current ones
- Develop and implement an Employee Engagement Strategy
- Deliver high quality training to employees at all levels to ensure that they have the knowledge, skills and abilities to do their jobs safety and effectively

- Enhance our Contractor Safety Management Program to ensure that all contractors meet our high standard for workplace safety
- Update the Emergency Evacuation Plan and deliver an updated training session to all Wardens and supervisory staff. All employees will also receive an updated training session.
- Facilitating wellness initiatives (including a Wellness Fair)
- Leading corporate events to support North American Occupational Safety and Health Week (NAOSH).
- Delivering the Highline Hazards presentation to youth in the community.
- Developing and delivering a dig up prevention campaign in the community.

Recent achievements regarding Health and Safety:

1. Zero injuries in the workplace.

- Thunder Bay Hydro achieved Zero lost time incidents in 2011. At year end, utility staff had worked 619 days without a lost time incident. Although this is an exceptional achievement, our commitment to Target Zero means never being satisfied with Safety performance. Continual effort is required to maintain this level of performance.
- Increased safety awareness at work and at home to promote employee wellness.
- Detailed reporting of Thunder Bay Hydro's Safety Management System and the progress made with its programs and initiatives have been presented throughout the year to the Board.
- Delivery of 77 training sessions and workshops
- Supported trades training for 15 apprentices in a variety of trades
- Updating our Hazard Identification and Risk Assessment
- Development of work procedures
- Workplace assessments by Thunder Bay Hydro's Ergonomic Change Team to prevent musculoskeletal disorders

- Updates to Thunder Bay Hydro's Safety Accountability Program which includes enhancements to workplace inspections
- Enhanced reporting through the Human Resources Information System
- Updates to the First Aid Program including the purchase and training relating to Automatic External Defibrillators
- External speakers on topics relating to employee wellness and developing a healthy lifestyle
- Creation of a Harassment, Discrimination and Violence Prevention Program which included training of all staff, an external audit of our physical workplaces and several enhancements to our security

2. A corporate culture where safety is of primary importance in decision making.

- Significant continued emphasis was put on Target Zero as well as specific initiatives such as: celebration of milestone safety events; creating an updated New Hire Orientation Program, expanding our Job Planning and Hazard Identification Program; and increasing employee involvement in the Safety Management System.
- A strong safety culture is evident in decision making throughout the corporate structure from regular discussion at the Board level to budget decisions which support a strong safety program to the impact of safety on work guidelines and job planning.

3. Delivery of a strong Public Safety Program.

- Delivered the Highline Hazard and Energy Conservation Program to 1361 students in 2011.
- Helping to organize and supporting the Threads of Life Walk to kick off NAOSH Week;
- Continue to support St John Ambulance with their educational programs for grades 3 and 6 students
- Partnered with the Canadian Red Cross in their Emergency Preparedness program
- Annual delivery of the Take Your Kids to Work Day program

- Continued support for the Forum North Health and Safety Conference which includes regular speakers and sessions offered by Thunder Bay Hydro employees on topics relating to programs within its Safety Management System.
- Worked with Crime stoppers to develop a TV segment and newspaper article around preventing copper theft.
- Created a "Hit the Breaks, Not Us" public awareness campaign which was adopted by several utilities in Ontario (shown below):

- Progressive relationship with the Ministry of Labour (MOL).
- Continue to enjoy an excellent relationship due to ongoing efforts in strengthening Thunder Bay Hydro's communication with the MOL. No orders or fines were levied on Thunder Bay Hydro.
- Maintain the momentum of Target Zero.
- Maintaining the momentum of the Target Zero program takes a great deal of ongoing work. In addition to items identified above, which help support the program, the organization implemented a Committed to Safety Logo which was a Joint Health and Safety Committee initiative to provide a visual reminder of the importance of the three key parties working together. The logo is shown below:

THUNDER BAY HYDRO
IBEW Local 339
EMPLOYEES
Committed To Safety

4. The Committed to Safety Committee meets on a regular basis to ensure that steps are taken to maintain momentum. This has included celebrations to commemorate Safety milestones. Testing

- Updated the Asbestos Management Plan including tests of suspected materials
- Air quality testing in office areas
- Hydraulic and Dielectric testing of equipment and cover up
- Lead testing in areas containing suspect paint where renovations or demolition is to occur

Environment

Thunder Bay Hydro is committed to being an environmental leader. Thunder Bay Hydro embraces responsibility as a good corporate citizen in complying with environmental laws, standards and procedures by:

- Meeting legal regulatory requirements and look for ways to continuously improve environmental performance.
- Identifying, assessing and managing environmental risks and integrate environmental considerations into decisions.
- Identifying potential environment effects and undertakes corrective action to prevent environmental incidents.
- Ensuring employees and contractors understand their roles and responsibilities from an environmental perspective and have the necessary skills, training and knowledge to perform their duties.
- Promoting environmental awareness by working together with employees, contractors, suppliers, regulators, industry and the public.
- Conserving natural resources and minimize environmental impact by practicing the three ‘R’s’ – Reduce, Reuse and Recycle.
- Measuring and communicating the results of environmental performance.

Outsourcing

With the exception of auditing and training, all areas of the Safety Management System are created and implemented in-house.

Auditing

To ensure an unbiased third party view, Thunder Bay Hydro outsources the auditing function on a regular basis to assist in measuring progress, successes and to identify any gaps in the Safety Management System.

Training

Training is an integral part of the Safety Management System at Thunder Bay Hydro. Given the risks associated with the product, training is on-going to ensure that employees are fully competent in identifying the hazards associated with their work and to implement the appropriate barriers to protect themselves, co-workers and the public.

Due to the complexity and specialization in the courses delivered, the majority of training is outsourced to specialists. However, as a part of employee retention programs, more and more of Thunder Bay Hydro staff are being trained as trainers to deliver the more routine sessions. This also assists in Thunder Bay Hydro's cost reduction strategy.

Culture Strategy

The following is taken directly from the Corporate Strategic Plan approved by the Board in February:

<u>Long Term Corporate Goals:</u>

- Ensure that the Health and Safety of its Employees and the Public is Thunder Bay Hydro's first priority.

- Provide a reliable supply of electricity to the residents and businesses of Thunder Bay.
- Protect and grow the value of Thunder Bay Hydro to the Shareholder.

<u>Strategic Initiatives – specific to HR & Safety:</u>

Human Resources

- Ensuring Thunder Bay Hydro can continue to attract, develop and retain required Human Resources is a critical challenge. Meeting this challenge is becoming increasingly difficult and is becoming one of the greatest risks Thunder Bay Hydro faces.

  Long term success will require that Thunder Bay Hydro provide a fulfilling, fair, and challenging work environment that allows Thunder Bay Hydro to attract, develop, engage and retain high quality staff. A wide range of initiatives contribute to meeting this challenge:

- Assessment of Internal Management Skills and Management Skills Training

  A regular assessment of internal management skills occurs. This assessment feeds a multi-year plan of management skills. The goal of this plan will be to ensure current and future utility management staff has the necessary operational, financial, supervisory and strategic skills to effectively contribute to the management of Thunder Bay Hydro.

- Succession Planning Strategy

  This includes an analysis of probable succession scenarios for supervisory, and non-supervisory, positions and the establishment of temporary and permanent succession plans.

- Employee Engagement Strategy

  Includes regular updates to staff, through meetings and other communications, outlining the industry developments, challenges and overall Corporate Goals and

Strategies. There is also a process of 'translating' Corporate Strategies into departmental action plans and specific objectives, and coordination of objectives across the company to avoid conflict. There is ongoing communication of departmental and individual objectives to those responsible, and a regular program of comparing requirements to results and updating staff of this progress.

- Formal Employee Satisfaction Assessment

  Every two years employee satisfaction surveys are conducted to receive feedback upon which to base new initiatives and modify existing programs.

- Compensation Strategy

  Establish a strategy for fairly balancing target compensation levels with retention risk for union and non-union staff.

- Institutional Relationships/Partnerships

  Promote relationships with post-secondary institutions that will help ensure the long term availability of specific skills required by Thunder Bay Hydro.

- Internal Promotional Program

  Establish a strategy promoting the benefits of working at Thunder Bay Hydro to increase retention.

Health & Safety

- Thunder Bay Hydro is committed to creating and maintaining a Corporate Culture where Health and Safety are Thunder Bay Hydro's top priorities. Thunder Bay Hydro's 'Target Zero' program has been an unqualified success since its introduction and management has supported this program by ensuring awareness and competency regarding safe work practices in everything task. Health and Safety objectives and strategies include:

- Maintaining the momentum of the 'Target Zero' program, ensuring the program remains fresh and its profile high within Thunder Bay Hydro. To ensure this Thunder Bay Hydro embarked on a rebranding of sorts, launching our 'Committed to Safety' program. While 'Target Zero' remains our overall goal, the 'Committed to Safety' program goes a step further ensuring a focus on safety in everything our employees engage in, at home or at work.
- Ongoing Hazard Assessments and the development of new programs and training to ensure the safety of our staff and the public.

- Maintaining a Corporate Culture where Safety is of primary importance in decision making.

- Delivering programs to increase safety awareness at work and at home, and to promote employee wellness.

- Delivering a strong public safety program.

Administrative and General Expenses

Administrative and general expenses include expenses incurred in connection with the general administration of Thunder Bay Hydro's operations. Within Thunder Bay Hydro, the following functional areas are considered to be part of general administration and, as such, all expenses incurred within these functional areas are accounted for as administrative and general expenses:

- Members of the Executive Management Team;
- Executive Assistants of the Executive Management Team;
- Corporate Services, including Human Resources and Purchasing; and
- Financial Services, including Accounting, and Regulatory Services.

Executive Costs:

This team includes the President, Vice Presidents of Customer Service & Conservation, Finance, Human Resources & Safety and Power Systems and the Executive Assistants.

Corporate Services:

The Human Resources & Safety Division is responsible for human resource management for Thunder Bay Hydro, including resource planning, employee recruitment and training, labour relations, and benefits administration. Additionally, it is responsible for ensuring a healthy and safe work environment for all employees, including the development and execution of the corporation's health and safety strategy, safety training and reporting.

The Health and Safety function exists at Thunder Bay Hydro to implement and maintain a Safety Management System that facilitates the achievement of the corporation's first priority, which is to secure the Health and Safety of our employees and the public.

Due to the modification of CGAAP accounting principles, for 2013 the Purchasing department costs have been expensed and considered Corporate Services. The Purchasing Department is responsible for procuring the required quality and quantity of material, supplies and services for all users in the most effective, timely and efficient manner and is objective and equitable in its treatment of all vendors.

Financial Services:

The Finance Division is responsible for the preparation of statutory, management and Board of Directors financial reporting; all daily accounting functions, including accounts payable, accounts receivable, compensation and payroll, including OMERS administration and general accounting; treasury functions including cash management, risk management, accounting systems and internal control processes; preparation of consolidated budgets and forecasts; and supporting tax compliance.

The Regulatory Services department within the Finance Division is responsible for all regulatory reporting and compliance with applicable codes and legislation governing Thunder Bay Hydro.

The department handles all regulatory reporting including development and preparation of rate filings, performance reporting, and compliance.

In accordance with the OEB's APH, the following is a summary of the categories of expenditures that are included in administrative and general expenses:

1. Salaries and expenses for all employees working within the above noted functional areas including:

- Executive salaries and expenses;
- Management salaries and expenses; and
- General and administrative salaries and expenses.

2. Outside services employed include, but are not limited to consulting and professional fees of accountants and auditors, actuaries, legal services, public relations counsel and tax consultants.

3. Office supplies and expenses specifically related to the administrative and general functional departments, as noted above.

4. Insurance premiums to protect Thunder Bay Hydro against losses and damages, including owned or leased property used in its utility operations, as well as injuries and damages claims of employees or others, losses not covered by insurance, and expenses incurred in the settlement of claims. Thunder Bay Hydro currently maintains prudent levels of Comprehensive General Liability insurance, including Enhanced Directors and Officers' Liability Insurance, as well as property and automobile insurance.

5. Annual expense for post-retirement benefits provided to eligible Thunder Bay Hydro employees in accordance with company policy and as provided in the collective bargaining agreement between Thunder Bay Hydro and its union. The annual expense and liability are determined in accordance with Section 3461 of the CICA Handbook and supported by an actuarial valuation that is completed every three years.

6. Regulatory expenses incurred in connection with Decisions and Orders on Cost Awards for hearings, proceedings, technical sessions, and other matters before the OEB or other regulatory bodies, including annual assessment fees paid to a regulatory body. Annual fees assessed by the OEB are included in this expenditure category.

OM&A DETAILED COSTS TABLES

Table 4-2.3 - Detailed Variance Analysis- Operation Expenses

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
					Variance ($)	Percentage	Variance ($)	Percentage
Reporting Basis		**CGAAP**	**CGAAP**	**MCGAAP**				
Operations								
5005	Operation Supervision and Engineering	$ 264,373	$ 317,704	$ 580,788	$ 316,415	119.7%	$ 263,084	82.8%
5010	Load Dispatching	$ 816,699	$ 782,901	$ 785,902	$ (30,797)	(3.8%)	$ 3,001	0.4%
5012	Station Buildings and Fixtures Expense	$ 309,836	$ 289,462	$ 339,979	$ 30,143	9.7%	$ 50,517	17.5%
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5016	Distribution Station Equipment - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 93,130	$ 162,502	$ 86,126	$ (7,004)	(7.5%)	$ (76,377)	(47.0%)
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 106,084	$ 177,801	$ 273,101	$ 167,017	157.4%	$ 95,300	53.6%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expe	$ 414,815	$ 694,570	$ 778,605	$ 363,790	87.7%	$ 84,035	12.1%
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5035	Overhead Distribution Transformers - Operation	$ 253,459	$ 191,683	$ 200,782	$ (52,677)	(20.8%)	$ 9,099	4.7%
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 10,287	$ 25,014	$ 44,699	$ 34,412	334.5%	$ 19,685	78.7%
5045	Underground Distribution Lines and Feeders - Operation Supplies and E	$ 5,809	$ 23,480	$ 24,150	$ 18,341	315.7%	$ 670	2.9%
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ 71,865	$ 254,701	$ 186,171	$ 114,306	159.1%	$ (68,530)	(26.9%)
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -		$ -	
5065	Meter Expense	$ 396,762	$ 241,431	$ 232,948	$ (163,814)	(41.3%)	$ (8,483)	(3.5%)
5070	Customer Premises - Operation Labour	$ 8,773	$ (921)	$ 1,355	$ (7,418)	(84.6%)	$ 2,276	(247.1%)
5075	Customer Premises - Operation Materials and Expenses	$ 37,465	$ 14,651	$ 13,572	$ (23,893)	(63.8%)	$ (1,079)	(7.4%)
5085	Miscellaneous Distribution Expenses	$ -	$ 9,814	$ 11,526	$ 11,526		$ 1,712	17.4%
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -		$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -		$ -	
5096	Other Rent	$ -	$ -	$ -	$ -		$ -	
Total - Operations		$ 2,789,357	$ 3,184,794	$ 3,559,704	$ 770,347	27.62%	$ 374,910	11.8%

Table 4-2.4 - Detailed Variance Analysis- Maintenance Expenses

Account	Description	Last Board-approved Rebasing	Most Current Actuals Year 2011	Test Year	Test Year Versus Last		Test Year Versus Most	
					Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Maintenance		CGAAP	CGAAP	MCGAAP				
5105	Maintenance Supervision and Engineering	$ 548,396	$ 505,469	$ 957,979	$ 409,583	74.7%	$ 452,510	89.5%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 12,499	$ 13,780	$ 16,185	$ 3,686	29.5%	$ 2,405	17.5%
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -		$ -	
5114	Maintenance of Distribution Station Equipment	$ 286,238	$ 135,789	$ 236,785	$ (49,453)	(17.3%)	$ 100,997	74.4%
5120	Maintenance of Poles, Towers and Fixtures	$ 133,991	$ 177,170	$ 202,530	$ 68,539	51.2%	$ 25,360	14.3%
5125	Maintenance of Overhead Conductors and Devices	$ 686,177	$ 631,804	$ 961,649	$ 275,472	40.1%	$ 329,844	52.2%
5130	Maintenance of Overhead Services	$ 344,777	$ 345,825	$ 358,829	$ 14,052	4.1%	$ 13,004	3.8%
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 716,115	$ 631,766	$ 744,289	$ 28,174	3.9%	$ 112,523	17.8%
5145	Maintenance of Underground Conduit	$ 17,669	$ 37,679	$ 29,729	$ 12,060	68.3%	$ (7,950)	(21.1%)
5150	Maintenance of Underground Conductors and Devices	$ 164,495	$ 100,913	$ 137,629	$ (26,866)	(16.3%)	$ 36,716	36.4%
5155	Maintenance of Underground Services	$ 74,510	$ 120,082	$ 179,003	$ 104,493	140.2%	$ 58,921	49.1%
5160	Maintenance of Line Transformers	$ 64,866	$ 86,237	$ 127,355	$ 62,489	96.3%	$ 41,118	47.7%
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -		$ -	
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -		$ -	
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5175	Maintenance of Meters	$ -	$ -	$ -	$ -		$ -	
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -		$ -	
Total - Maintenance		$ 3,049,733	$ 2,786,514	$ 3,951,962	$ 902,229	29.58%	$ 1,165,448	41.8%

Table 4-2.5 - Detailed Variance Analysis- Billing & Collecting Expenses

Account	Description	Last Board-approved Rebasing Year (Year)	Most Current Actuals Year 2011	Test Year	Test Year Versus Last		Test Year Versus Most	
					Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Billing and Collecting		CGAAP	CGAAP	MCGAAP				
5305	Supervision	$ -	$ -	$ -	$ -		$ -	
5310	Meter Reading Expense	$ 133,816	$ 286,137	$ 293,296	$ 159,480	119.18%	$ 7,159	2.50%
5315	Customer Billing	$ 1,271,382	$ 1,075,646	$ 1,197,595	$ (73,787)	(5.80%)	$ 121,949	11.34%
5320	Collecting	$ 679,308	$ 499,473	$ 513,803	$ (165,505)	(24.36%)	$ 14,330	2.87%
5325	Collecting - Cash Over and Short	$ -	$ -	$ -	$ -		$ -	
5330	Collection Charges	$ -	$ -	$ -	$ -		$ -	
5335	Bad Debt Expense	$ 160,000	$ 84,356	$ 130,000	$ (30,000)	(18.75%)	$ 45,644	54.11%
5340	Miscellaneous Customer Accounts Expenses	$ -	$ -	$ -	$ -		$ -	
Total - Billing and Collecting		$ 2,244,506	$ 1,945,612	$ 2,134,694	$ (109,812)	(4.89%)	$ 189,082	9.72%

Table 4-2.6 - Detailed Variance Analysis- Community Relations Expenses

Account	Description	Last Board-approved Rebasing	Most Current Actuals Year 2011	Test Year	Test Year Versus Last		Test Year Versus Most	
					Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Community Relations		**CGAAP**	**CGAAP**	**MCGAAP**				
5405	Supervision	$ -	$ -	$ -	$ -		$ -	
5410	Community Relations - Sundry	$ -	$ -	$ -	$ -		$ -	
5415	Energy Conservation	$ 78,732	$ 95,149	$ 110,062	$ 31,330	39.79%	$ 14,913	15.67%
5420	Community Safety Program	$ 14,892	$ 11,902	$ 31,800	$ 16,908	113.54%	$ 19,898	167.19%
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -		$ -	
5505	Supervision	$ -	$ -	$ -	$ -		$ -	
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -		$ -	
5515	Advertising Expenses	$ 134,715	$ 90,313	$ 120,271	-$ 14,444	(10.72%)	$ 29,958	33.17%
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations		$ 228,339	$ 197,363	$ 262,133	$ 33,794	14.80%	$ 64,770	32.82%

Table 4-2.7 - Detailed Variance Analysis- General & Administrative Expenses

Account	Description	Last Board-approved Rebasing	Most Current Actuals Year 2011	Test Year	Test Year Versus Last		Test Year Versus Most	
					Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Administrative and General Expenses		CGAAP	CGAAP	MCGAAP				
5605	Executive Salaries and Expenses	$ 951,809	$ 816,361	$ 914,411	$ (37,398)	(3.93%)	$ 98,050	12.01%
5610	Management Salaries and Expenses	$ -	$ -	$ -	$ -		$ -	
5615	General Administrative Salaries and Expenses (1)	$ 1,236,519	$ 1,168,190	$ 1,414,365	$ 177,846	14.38%	$ 246,175	21.07%
5620	Office Supplies and Expenses (1)	$ 213,361	$ 254,573	$ 296,300	$ 82,939	38.87%	$ 41,727	16.39%
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -		$ -	
5630	Outside Services Employed	$ 230,899	$ 171,944	$ 208,800	$ (22,099)	(9.57%)	$ 36,856	21.43%
5635	Property Insurance	$ 32,550	$ 31,239	$ 31,328	$ (1,222)	(3.75%)	$ 89	0.29%
5640	Injuries and Damages	$ 315,652	$ 218,934	$ 281,747	$ (33,905)	(10.74%)	$ 62,813	28.69%
5645	OMERS Pensions and Benefits	$ -	$ 745,946	$ 897,374	$ 897,374		$ 151,428	20.30%
5646	Employee Pensions and OPEB		$ -	$ -	$ -		$ -	
5647	Employee Sick Leave		$ -	$ -	$ -		$ -	
5650	Franchise Requirements	$ -	$ -	$ -	$ -		$ -	
5655	Regulatory Expenses	$ -	$ 145,954	$ 181,300	$ 181,300		$ 35,346	24.22%
5660	General Advertising Expenses	$ -	$ -	$ -	$ -		$ -	
5665	Miscellaneous General Expenses	$ 258,406	$ 117,191	$ 145,972	$ (112,434)	(43.51%)	$ 28,781	24.56%
5670	Rent	$ 308,288	$ 286,746	$ 291,905	$ (16,383)	(5.31%)	$ 5,159	1.80%
5672	Lease Payment Charge		$ -	$ -	$ -		$ -	
5675	Maintenance of General Plant	$ 75,643	$ 73,514	$ 86,220	$ 10,577	13.98%	$ 12,706	17.28%
5680	Electrical Safety Authority Fees	$ -	$ -	$ -	$ -		$ -	
5681	Special Purpose Charge Expense	$ -	$ 164,327	$ -	$ -		$ (164,327)	
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -		$ -	
5695	OM&A Contra Account	$ -	$ (249,233)	$ -	$ -		$ 249,233	(100.00%)
6205	Donations	$ -	$ 40,806	$ 24,200	$ 24,200		$ (16,606)	(40.69%)
6205	Donations, Sub-account LEAP Funding		$ -	$ -	$ -		$ -	
Total - Administrative and General Expenses		$ 3,623,127	$ 3,986,493	$ 4,773,922	$ 1,150,795	31.76%	$ 787,430	19.75%
Total OM&A		$ 11,935,063	$ 12,100,776	$ 14,682,415	$ 2,747,352	23.02%	$ 2,581,639	21.33%
Adjustments for non-recoverable items								
5681	Special Purpose Charge Expense	$ -	$ 164,327	$ -	$ -		$ (164,327)	(100.0%)
6205	Donations[1]	$ -	$ 40,806	$ 24,200	$ 24,200		$ (16,606)	(40.69%)
					$ -		$ -	
		$ -			$ -		$ -	
		$ -			$ -		$ -	
Total Recoverable OM&A		$ 11,935,063	$ 11,895,643	$ 14,658,215	$ 2,723,152	22.82%	$ 2,762,572	23.22%

VARIANCE ANALYSIS ON OM&A COSTS

Thunder Bay Hydro has provided a detailed OM&A expense analysis covering the periods from its last cost of service application. An analysis of expense changes by cost driver is provided in Table 4-2.8 with explanations below.

Table 4-2.8 - OM&A Cost Driver Table

OM&A	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MCGAAP
Opening Balance	11,935,063	11,964,973	12,457,522	12,100,776	13,785,463
Overtime (5)	304,342				
Outside Services (6) (a)	172,985				
Outside Services (6) (b)			(135,917)		
Outside Services (6) (c)				123,233	
Allocation of I.T. Costs (7)	86,988				
Overhead charges (8) (a)			(231,106)		
Overhead charges (8) (b)				176,133	
Bad Debt Expense (9)		82,630	(109,226)		
Special Purpose Charge		224,892	(60,564)	(164,327)	
Safety Clothing (10)			86,518		
Corporate Benefits (11) (a)	(94,640)				
Corporate Benefits (11) (b)					60,671
OM&A Contras (12) (a)		(134,968)	(114,265)	249,232	
Smart Meter LTD (2009-2011) Operating Costs 12 (b)				608,695	(608,695)
SMIRR (Smart Meter Incremental Revenue Requirement) Meter Reading and I.T.) (12) (c)				402,878	
Professional fees (13) (a)	(90,691)				
Professional fees (13) (b)				179,199	
Professional fees (13) (c)					(83,549)
Capitalization Policy Change (Overhead Charges not directly attributable to capital net of labour & other materials on transformer & meter changeouts now capitalized)					1,264,420
Training (14)	(127,704)				
Wages 15(a)	(128,403)				
Wages 15 (b)		221,627			
Wages 15 (c)					96,504
Various expense variances below materiality threshold	(92,967)	98,368	207,814	109,644	167,601
Closing Balance	$ 11,964,973	$ 12,457,522	$ 12,100,776	$ 13,785,463	$ 14,682,415

Notes:

1 For each year, a detailed explanation for each cost driver and associated amount is required

2 The closing balance for each year becomes the opening balance for the next year.

3 If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated

4 Opening Balance for "Last Rebasing Year" (cell B15) should be equal to the Board-Approved amount.

Thunder Bay Hydro Explanatory Notes supporting the Cost Driver information above:

5 Overtime costs are significantly over budget for two reasons. The first being the timing of the hiring of the staff increase in complement. See explanation provided at 15 (a) below. The second reason being that Thunder Bay Hydro was overly optimistic when striking the 2009 COS budget. At that time, the judgement was that the hiring of the PLT apprentices (5) would add additional manpower to enable reduction of overtime required. In reality overtime in the OM&A activities is largely driven by storm activity and customer requirements. Experience has confirmed that the budget as struck was unrealistic.

(6) (a) Outside services in the 2009 Board Approved budget was reduced by $147,500 for the annualization of the contract Meter Reading services that would be phased out over the IRM period to the next rebasing. The 2009 reflects the first of year of actual costs which were $101,000 higher than the annualized amount. Tree trimming budget went over by $80,000. The third significant cost increase was approximately $47,000 as a result of contracting out the arrears work. Efficiencies in salary & benefit costs would offset this cost increase. Finally, approximately $20,000 is a reduction of outside service costs as a result of deferring station decommissioning activities. The balance of the variance ($35,015) is a combination of variances in a number of other accounts, all individually insignificant.

(6) (b) The third and final year of the Meter Reading costs decreases occurred in 2011. The 2011 costs reduced a further $64,000 from the 2010 historicals to the $25K expected annual level. Additionally, 2011's tree trimming dropped $44,000 from the 2010 level of activity and outside services for vacuum excavation services dropped $43,000 from 2010.

(6) (c) There are several costs driving this increase, the more significant ones being: (1) The tree trimming budget is a combination of increased work annually for the fourth of the seven year annual increment as per the Forestry Vegetation plan as discussed in Thunder Bay Hydro Asset Management Plan found in Exhibit 2, along with a price increase upon contract renewal in 2012. Combined, this is resulting in an increase of $67,000; (2) Thunder Bay Hydro outsourced the bill print, stuff and mailing in May of 2012 resulting in increased costs of $79,500 in outside services (note that although this expense increased, acheived savings are spread throughout other expenses, none of which individually exceed the materiality threshhold); (3) $46,000 estimated for the demolition of a Distribution Substation; and (4) reduced spending $38,000 on consulting work for Human Resources in staffing vacancies .

7 Subsequent to the approval of the 2009 budget, Thunder Bay Hydro faced a "skilled resource"challenge. A majority of Thunder Bay Hydro's skilled union I.T. staff members had job offers at a significantly higher wage rate. To mitigate the risk of the loss of skilled staff, Thunder Bay Hydro made adjustments to the I.T. staff wages to reflect market conditions. This resulted in approximately $75,000 compensation increase over and above the budget for the department. This coupled with the benefit impact of the wage adjustment accounts for the departments increases, hence the allocation of this department to other departments.

8 (a) Overhead charges to OM&A were significantly reduced as a result of the $575,000 increase in sub-contracting charges to capital work in 2011; $390,000 increase in PLT labour charge to capital and $70,000 of Engineering time charged directly to capital jobs. The result of the previous impacts was to reduce the amount of the costs to be burdened and increased the base over which overheads are allocated resulting in a significant reduction in the overheads charged to OM&A.

8 (b) See the above explanation for 2011. The 2012 sub-contracting work charged to capital in 2012 reduced back to the 2010 level for a reduction of the $575,000. This combined with increased department costs caused the allocation to OM&A to increase.

9 Thunder Bay Hydro did not file for a rate rider to collect from customers the late payment class action settlement in the amount of $161,043 in 2010. This higher cost was partially offset by lower write-offs. The 2011 decrease in this cost is likewise caused by this settlement.

10 Purchase of fire retardant clothing was negotiated into the collective agreement for purchase every two years. This is a significant cost (approximately $80,000) every other year with 2011 being the first in the rebasing period (should have been a 2010, then 2012 purchase; however, timing of the receipt of the goods resulted in the higher costs in both 2011 and 2012). The 2013 cost is an annualized cost over the next rebasing period.

11 (a) Corporate Benefits were $94,640 lower than budgeted in the 2009 COS for the following reasons: (1) approximately $85,000 variance as a result of higher Post Retirement Benefit actuarial assumptions used with respect to losses and benefits paid than the 2009 results; (2)Health and Dental costs came in under budget by approximately $51,000; (3) the cost reduction due to Smart Meter deferral was $17,000 higher than budgeted given that the budget was a four year annualized reduction amount; and (4) underestimate of costs mainly with respect to OMERs , LTD and WSIB by ($58,540).

11 (b) The most significant driver of the increased costs of $60,671 in the 2013 Test year is OMERs. The actual premium increases based on existing 2012 wage projections amount to approximately $100K, 45 % of which is OM&A related.

12 (a) Smart Meter Initiative program commenced in April of 2009 and completed December 31, 2011. As per Thunder Bay Hydro's Smart Meter Disposition application Smart Meter OM&A costs were no longer deferred effective January 1, 2012. The credits in 2010 and 2011 represent incremental OM&A costs within Thunder Bay Hydro's various departments that were contraed. The 2012 debit reflects the cessation of deferral.

12 (b) As per the Accounting Procedures Handbook, Thunder Bay Hydro has recognized the life-to-date Smart Meter Incremental operating costs that were deferred from commencement of the project to December 31, 2011. The $608,695 represents the recognition of the 2006 through 2011 operating and administration costs related to the Smart Meter Initiative.

12 (c) Thunder Bay Hydro has shown seperately for 2012, the incremental costs as a result of the Smart Meter Initiative. The costs include a MAS operator, operational data store services, cellular communication to the AMI network fees, bill print modifications, TOU web presentment costs, security and customer education costs. For 2013, the costs have been incorporated into the respective costs (i.e. outside service, wages, etc.).

13 (a) Professional fees in the 2009 COS reflected $33,000 for the annualized cost of preparing the COS whereas the 2009 actuals were $10,000 as the bulk of the costs incurred in the preparation of the COS would have all been incurred in the 2008 fiscal year. Legal fees with respect to procurement matters came in $20,000 less than budgeted and Human Resource legal and professional fees were $34,500 less than budget. Thunder Bay Hydro endeavours to take on as much of research work in house as per internal competencies; however, this is a difficult item to budget for as one case matter could potentially be significant. Professional fees budgeted in anticipation of recommendations from a E&USA Zeroquest audit were not required given Thunder Bay Hydro scored well on such. Additionally funds budgeted for specific studies were deferred due to Distribution Revenue lower than budget.

13 (b) Regulatory related professional fees are $23,500 higher in 2012 given a Motion to Vary the 2012 IRM relating to the disposition of OEB account 1562 PILS filing by Thunder Bay Hydro. Additionally, consulting fees relating to the preparation of the 2013 COS application have resulted in $33,000 increased costs. Professional fees are budgeted for employment testing for both new and existing hires, arbitrator/mediator and legal fees for potential labour relations issue resolution, medical fees associated with employment medicals for new staff. As noted above, the account has been underspent; however, the potential is significant . 2012 has two pending lawsuits with potentially significant costs. Professional fees for procurement has also increased given the complexity and size of the purchases Thunder Bay Hydro is undertaking. Thunder Bay Hydro has increasingly utilized legal counsel to assist with procurement issues given the turnover of staff in the Purchasing Department over the past few years.

13 (c) The professional fees in 2013 have decreased from the 2012 given the anticipated resolution of the two lawsuits and the fact that the 2013 COS Application costs have been annualized.

14 Training costs are down in 2009 historical due to a number of factors -due to the timing of the hiring of apprentices in 2009, some of the apprenticeship training costs have been pushed ahead by a year (i.e. the four year training plan did not commence until 2010); the staff member that oversees this function was off on a maternity leave and the position was not not replaced causing fewer educational training courses coupled with fewer attendance numbers; no local professional development courses were offered; and workload issues are among the more significant drivers of this cost reduction.

15 (a) The most significant drivers of the wage reduction in the historical 2009 from the 2009 COS budget are (1) Thunder Bay Hydro outsourced it's Arrears & Vacancy work in 2009 resulting a shifting of costs between wages and outside services. The wage reduction from budget in this department amounting to approximately $71,000 and (2) Timing of the hiring of staff and vacancies in positions contributed to a lower than actual budgeted wage cost in 2009 as well for both Load Dispatching and Stations amounting to approximately $83,000. The higher Smart Meter OM&A contra combined with the timing of the hiring of the Meter Apprentice resulted in lower that budgeted costs of $34,000 for the Meter & Service Department. These increases are offset by the PLT OM&A wages costs exceeding the 2009 COS budget by approximately $84,000; the main reason being that the budgeted amount for this group allocated to "Downtime" overhead burden was lower resulting in higher direct labour charges to the various OM&A accounts. The balance of the variance is made up of several smaller variances.

15 (b) Wage increase drivers are a combination of apprentice progression increases, MAS operator for Smart Meter Initiative in OM&A costs (contra in 5645) on for full year versus partial year coupled with the cessation of charges to Smart Meter capital, regular annual contract increases and increased part-time workers as a result of increased activity with respect to work done for the affiliate (Smart Meter and Conservation).

15 (c) The wage increase from the 2012 Bridge Year to 2013 Test Year is a result of the annual contract increase and an net increase in complement in 2013. As noted in Exhibit 4, Tab 2, Schedule 4, the increased complement is required to prepare for upcoming retirements and increased capital and maintenance work.

Variance Analysis by Account

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28 2012, Thunder Bay Hydro has provided variance analyses for the 2013 Test Year vs. 2009 Board-approved Budget (last rebase year) and between the 2013 Test Year and 2011 Actual (Most Current Actual). Thunder Bay Hydro has reviewed the variance of each USoA account and provided explanations for variances exceeding a materiality threshold of $85,000. The variances are indicated in the following tables and an explanation of each variance is presented in the following section.

LAST REBASING-2009 VERSUS 2013 TEST YEAR:

5005 – Operations Supervision and Engineering $316,415

Of the increase in this OM&A account from the 2009 COS, $181,415 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. The second driver of the cost variance in this OEB account is labour, which represents approximately 70% of the total burden department costs. The wage increase in each of 2010, 2011 and 2012 was 3% ($180,000 increase from the last rebasing assuming same labour complement).

5020 – Overhead Distribution Lines & Feeders $167,017

Of the increase in this OM&A account from the 2009 COS, $55,936 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. The variance for increased spending in the 2013 Test Year is due to increasing labour and labour associated costs in relation to completing risk assessments on Thunder Bay Hydro's lines and feeders.

5025 – Overhead Distribution Lines & Feeders –Supplies & Expenses $363,790

Of the increase in this OM&A account from the 2009 COS, $46,046 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. The increase in spending in this account is

due to the additional apprentices and required supplies and standard equipment for additional fleet.

5055 – Underground Distribution Transformers – Operations $114,306

A reduction of $43,013 is related to (1) the 2013 Test Year change in the depreciation and capitalization policy and (2) the capitalization of the labour and other material costs associated with transformer replacement. Previously such costs were only capitalized for first-time installs. As explained in Exhibit 4, Tab 4 the net OM&A adjustment has decreased this account.

The $157,319 increase from the 2009 COS to the 2013 Test Year is a result of an additional FTE required to manage the increasing demand such as on underground switching for contractors performing work around Thunder Bay Hydro's underground plant. 2013 includes greater than anticipated transformer and base work identified through Thunder Bay Hydro's risk assessments.

5065 – Meter Expense ($163,814)

This OM&A account has increased from the 2009 COS by $10.666 and this is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. The costs exclusive of the impact of the change in capitalization policy decreased $188,862 as a result of Thunder Bay Hydro reducing the work crew by 1 FTE due to fewer meter replacements required with the new smart meters. The 2009 budget had anticipated that a Meter Apprentice was to be hired; however, Thunder Bay Hydro revisited this decision and deferred such hiring until more knowledge of the changing workload has been gained.

5105 – Maintenance Supervision and Engineering $409,583

Of the increase in this OM&A account from the 2009 COS, $383,531 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. The second driver of the cost variance in this OEB account is labour and labour associated costs, which represents approximately 70% of the total burden department costs. The wage increase in each of 2010, 2011 and 2012 was 3% ($180,000 increase from the last rebasing assuming same labour complement).

5125 – Maintenance of Overhead Conductors & Devices $275,472

Of the increase in this OM&A account from the 2009 COS, $220,216 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. The majority of the variance is due to additional overtime incurred as a result of storm activity and customer requirements.

5155 – Maintenance of Underground Services $104,493

Of the increase in this OM&A account from the 2009 COS, $35,034 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. The other contributor to the variance is the labour hours that have been trending higher in recent years due to underground infrastructure reaching end-of-life. Another factor is the changeover from conventional to smart meters, which has been driving an increased number of failures due to meter base issues discovered during the meter change and are still being completed presently and in 2013.

5310 – Meter Reading Expense $159,480

The increase in this account is due to Thunder Bay Hydro having a full-functioning smart meter department that has been rolled into rate base in the 2013 Test Year. Costs include 1 FTE AMI Data Systems Co-ordinator, increased internet charges to send and receive data with the collectors, and monthly Operational Data Storage (ODS) charges. In the 2009 Board-approved budget, Thunder Bay Hydro had $255,000 of meter reading OM&A costs which was reduced to $147,500 representing annualization of these cost that were to be phased out over the 2009 Cost of Service period.

5320 – Collecting ($165,505)

The contributors to the $165,505 decrease in this account are two-fold. First there was a retirement of 1 FTE within the collecting department and Thunder Bay Hydro took the opportunity to reorganize the Customer Service position's duties to other full and part-time employees. Second, there was a decrease in costs realized when Thunder Bay Hydro decided to outsource the notice delivery, cut offs, reconnections, trucking, and related collection activities.

5615 – General Administrative Salaries and Expenses $177,846

The majority of the variance in this account is due to the fact that in the 2013 Test Year the Purchasing Department is considered a corporate expense versus part of the Material overhead as in the 2009 Board-approved budget. Also, the 2013 Test Year includes an additional FTE in Finance was added mid-way through 2011.

5645 – OMERS Pensions and Benefits $897,374

In 2011 the OMERS Pensions and Benefits expense was included in Account 5645; however, in the 2009 Board-approved budget, these costs were included as part of the salaries and benefits of the various departments and not broken out separately.

5655 – Regulatory Expenses $181,300

In the 2009 Cost of Service application, Thunder Bay Hydro had not directed costs to this account. As per OEB direction in EB-2008-0245, Thunder Bay Hydro commenced recording regulatory costs in 5655 as described in the APH.

5665 – Miscellaneous General Expenses $(112,434)

See the explanation above in OEB Account 5655. In the last Board-approved rebasing year, Thunder Bay Hydro had included the regulatory costs in this account.

2011 ACTUAL VERSUS 2013 TEST YEAR:

5005 – Operations Supervision and Engineering $263,084

Of the increase in this OM&A account from 2011, $181,415 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. Also, another cost driver is labour, in which labour has increased by annual contract increases, and 2013 reflects full complement in the Engineering department.

5020 – Overhead Distribution Lines and Feeders-Operation Labour $95,300

Of the increase in this OM&A account from 2011, $55,936 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. Also, the majority of the variance for increased spending in the 2013 Test Year is the increase in labour to perform risk assessments as part of the Thunder Bay Hydro's Risk Assessment Program.

5105 – Maintenance Supervision and Engineering $452,510

Of the increase in this OM&A account from 2011, $383,531 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. Also, another cost driver is labour, in which labour has increased by annual contract increases, and 2013 reflects full complement in the Engineering department.

5114– Maintenance of Distribution Station Equipment $100,997

Of the increase in this OM&A account from 2011, $20,944 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. Also, the increase in the 2013 Test Year is primarily due to 1 additional FTE and wage increases from employee advancements.

5125 – Maintenance of Overhead Conductors & Devices $329,844

Of the increase in this OM&A account from 2011, $220,216 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. Also, the increase in the 2013 Test Year is the result of an increase in overtime for the work that will be required by joint permit's being issued on Thunder Bay Hydro's poles for increased capital upgrades. Thunder Bay Hydro is also seeing new joint use requests on poles not previously rented. On many occasions, Thunder Bay Hydro is required at its own expense to perform make-ready work. This may be work anywhere from changing rotten cross arms to pulling up a conductor which is too low.

5135 – O/H Distribution Lines & Feeders – Right of Way $112,523

Of the increase in this OM&A account from 2011, $5,800 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. Primarily, however, the increase in the 2013 Test Year is the result of keeping on target with the 7 year Forestry Management Plan and rate increases by external contractors.

5315 – Customer Billing $121,949

The 2013 Test Year will see additional expenses in Customer Billing due to a ½ FTE position required to assist in the additional workload as a result of increased Renewable Generation OPA Contracts. In addition, the allocation of the IT department has increased to this account due to the impact of Smart Meters and TOU Billing.

5605 – Executive Salaries and Expense $98,050

In 2011, the VP Power Systems position was vacant for several months but has since then been filled.

5615 – General Administrative Salaries and Expenses $246,175

Of the increase in this OM&A account from 2011, $149,766 is related to the 2013 Test Year change in the depreciation and capitalization policy. As explained in Exhibit 4, Tab 4 increased burden allocation to OM&A has increased. In the 2013 Test Year the Purchasing Department is considered a corporate expense. In the 2009 Board-approved budget Purchasing was included in material overhead. Also an increase of 1 FTE in Finance (Business & Regulatory) was realized mid-way through 2011.

5645 – OMERS Pension and Benefits $151,428

OMERS premium increases from 8.3% to 9.0% and 12.8% to 14.6%

5681 – Special Purpose Charge $(164,327)

The variance reflects elimination of the Special Purpose Charge in 2013 relative to 2011.

5695 – OM&A Contra $249,233

In 2011, Thunder Bay Hydro was still incurring and deferring Smart Meter OM&A costs and the expense was recorded as a contra in 5695. The Smart Meter program was deemed to be complete as at December 31, 2011 and therefore no further expenses have been deferred beyond this date.

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS

Thunder Bay Hydro's Total Compensation System

Introduction

Thunder Bay Hydro's total compensation system is comprised of a combination of fundamental elements - including both cash and non-cash rewards - designed to support the organization's compensation philosophy, motivate and reward performance aligned with critical business objectives, and provide a positive return on the significant dollars invested in compensation.

Merit Pay

As a performance driven organization, base salary is based on performance and tied directly to demonstrated behavioural competencies and Thunder Bay Hydro's values. At Thunder Bay Hydro, non-union employees achieve base line salary increases through goal setting and building behavioural competencies to improve individual skills to maximize potential and enhance their contribution to the business. The Performance Management System is a practical tool used to help both the employee and the organization achieve results. There is a partnership between the employee and supervisor to share in the responsibility of developing skills and abilities. It is the responsibility of the employee to take charge of their development while Thunder Bay Hydro provides them with the tools and coaching to achieve their development goals.

Merit pay is intended to provide a system to reward employee behaviours and values through increases to base pay. A merit increase is the amount of additional compensation added to current base salaries following a review of employee performance and is usually awarded in six-month increments until the incumbent has achieved the 100% salary for their respective position.

Thunder Bay Hydro has a formal and disciplined approach in awarding base line merit increases to individuals. Each Vice President reviews the performance of each non-union employee in their department, taking into consideration the remarks and comments from the employee's direct supervisor who conducted the review prior to the recommendation of any merit increase.

Final approval for merit increases resides with the Vice President, Human Resources & Safety who reviews all comments and recommendations to ensure such increases are warranted.

Incentive Based Pay

Thunder Bay Hydro seeks to encourage an incentive based performance culture by aligning employees' efforts with the corporate vision and the short and long-term goals of Thunder Bay Hydro. At present, an incentive based pay system exists only for the President. In the case of the President, the Board of Directors for Thunder Bay Hydro annually sets out strategic objectives that align to the organization's success and continued growth. Thunder Bay Hydro supports the Balanced Scorecard methodology in setting corporate and individual goals to foster continuous improvement and cost reductions that support a healthy balance sheet that provides value to customers by keeping rates reasonable.

The three pillars of Thunder Bay Hydro's goals focus on ensuring that the health & safety of Thunder Bay Hydro employees and the public is Thunder Bay Hydro's first priority; providing a reliable supply of electricity to the residents and businesses of Thunder Bay; and protecting and growing the value of Thunder Bay Hydro to Thunder Bay Hydro's shareholder.

One of Thunder Bay Hydro's beliefs is that 'Our Customers are the reason we exist'. Both corporate and individual goals and Thunder Bay Hydro's are structured to deliver and reward on the results of this belief. Corporate results are shared regularly with the organization as Thunder Bay Hydro tracks its efforts against outputs.

Executive Pay

Thunder Bay Hydro's executive pay philosophy considers compensation from throughout Ontario at other like-sized or similarly structured utilities, ensuring that executives are compensated at levels consistent with the mean of comparable organizations. Such compensation levels are reviewed on a regular basis.

Benefits

A comprehensive and competitive benefits package exists which includes medical and dental insurance, life insurance, vacation and leave policies and a company-sponsored retirement plan.

The plans are designed to address the health and welfare needs of the employee population. The benefit packages are consistent across the organization for 136 full-time employees, including the executive team. The only inconsistencies are Long Term Disability (LTD) coverage for a portion of the union group (grandfathered as the result of a merger and subsequent

negotiating process); life insurance coverage (some staff receive 2 times current base salary versus the majority 1.5 times current base salary); tiered health spending account (annual) amounts for non-union staff; and reduced, employee-funded partial benefits for participating part-time staff.

Head Count

Table 4-2.9 below summarizes Thunder Bay Hydro's head count for 2011, 2012 as well as the forecasted head count for 2013 and 2014. Numbers of part-time, and temporary/seasonal staff employed at points throughout the year, are also provided.

Table 4-2.9 – Head Count for 2011, 2012, 2013 and 2014

Class	2011	2012	2013 (Forecast)	2014 (Forecast)
Executive	5	5	5	5
Management/Supervisory	18	18	18	18
Management/Non-Supervisory	14	15	15	15
Management/Part-time	2	2	2	2
Unionized	88	91	**89 + 1 see below**	**90 + 1 see below**
Unionized/Part-time	8	7	7	7
Unionized/Temporary/Seasonal	15	14	13	13
Total	152	153	**151**	**152**

Executive

Executive complement is expected to remain constant throughout the period.

In 2011 Thunder Bay Hydro experienced the vacancy of one Executive due to resignation. This occurred at the end of June. From July 1, 2011 until November 22, 2011, the vacancy was filled internally on an acting basis resulting in a salary savings for that period. Effective November 23, 2011, the position was filled on a permanent basis by an internal candidate.

Management/Supervisory

In 2011, in response to increased regulatory pressures and increased workload, Thunder Bay Hydro increased the supervisory complement in the Finance Division by one with the introduction of the position Supervisor, Business & Regulatory Affairs. This position was in place effective May 16, 2011.

Additionally, it will be necessary to temporarily exceed complement in 2012 to prepare for an upcoming retirement in the Powerline Department to ensure that adequate training and skills transfer occurs with the retirement of one of the Line Supervisors at the end of the year. This overlap will range from one to three months.

Management/Non-Supervisory

Management/Non-Supervisory complement is expected to remain constant throughout the period.

Management/Part-time

Management/Part-time complement is expected to remain constant throughout the period.

Unionized

The unionized workforce is represented by the International Brotherhood of Electrical Workers, Local 339. The represented employees include tradespersons, technical, labour-intensive and administrative/clerical staff, sometimes referred to “office” and “outside” staff.

An increase in unionized positions between 2011 and 2012 are related to Thunder Bay Hydro’s apprenticeship/succession program whereby staff are hired and brought through their apprenticeship (4-5 years) in advance of pending retirements to ensure human resources are available to perform required work, as well as to reflect the increase in capital spending and the labour component required to complete that work.

For 2013 and 2014, the increase in staff is related to the same demographic and capital improvement challenges referred to above.

The additional staff for 2012/13/14 includes the following:

Table 4.2-10 – Additional Staff

Position	Addition	Comments
Powerline Technician Apprentices	4 (2012)	2 required to account for pending retirements; 2 to address increase in capital and maintenance
	6 (2013)	2 required to account for pending retirements; 4 to address increase in capital and maintenance
Station Electrician Apprentice	1 (2013)	To address increased workload; Seasonal
System Operator Apprentice	1 (2014)	To account for pending retirement.

** Additional staff allocated for pending retirements is temporary and is offset by other retirements previously accounted for, therefore refer to Table 4-2.11 for actual increases to complement.*

Converse to the above, a reduction of two full-time unionized positions will be realized in mid-2012 with the elimination of the position of Payroll Clerk and the reduction of hours for the Storekeeper, through attrition, in our Finance Division; and a reduction of one System Control Operator in our Power Systems Division.

<u>Unionized Part-time</u>

Unionized Part-time complement reduced by one between 2011 and 2012 due to the elimination of one part-time clerk in our Customer Service Department.

<u>Unionized/Temporary/Seasonal</u>

Unionized/Temporary/Seasonal complement will be reduced by one given the hiring of the Station Electrician Apprentice in 2013.

Employee Compensation and Benefits

The employee complement, compensation and benefit information is provided in Table 4-2.11 below.

Table 4-2.11 - Employee Compensation

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis						
Number of Employees (FTEs including Part-Time)[1]						
Executive	5.00	5.00	5.00	4.61	5.00	5.00
Management	17.00	16.65	16.66	17.64	17.98	18.00
Non-Union	15.02	13.20	11.78	13.40	13.95	13.95
Union	101.23	93.03	96.72	97.16	99.65	100.86
Total	138.25	127.88	130.16	132.81	136.58	137.81
Number of Part-Time Employees						
Executive	0.00	0.00	0.00	0.00	0.00	0.00
Management	0.00	0.00	0.00	0.00	0.00	0.00
Non-Union	2.00	3.00	3.00	2.00	2.00	2.00
Union	21.00	19.00	20.00	16.00	18.00	17.00
Total	23.00	22.00	23.00	18.00	20.00	19.00
Total Salary and Wages (**)						
Executive	0	687,934	706,235	684,622	726,005	733,879
Management	0	1,416,702	1,484,453	1,586,430	1,643,365	1,690,549
Non-Union	0	880,571	848,081	951,503	1,050,972	1,110,931
Union	0	6,124,612	6,481,559	6,874,456	6,859,870	7,110,731
Total	0	9,109,818	9,520,328	10,097,011	10,280,212	10,646,090
Current Benefits						
Executive	0	129,318	139,006	138,449	162,168	171,821
Management	0	271,006	300,304	326,707	376,685	408,617
Non-Union	0	170,799	182,165	204,508	244,127	259,195
Union	0	1,223,148	1,297,177	1,389,863	1,450,341	1,582,167
Total	0	1,794,271	1,918,652	2,059,527	2,233,321	2,421,801
Accrued Pension and Post-Retirement Benefits						
Executive	0	26,996	20,716	21,812	18,136	18,473
Management	0	56,574	44,755	51,471	42,127	43,932
Non-Union	0	35,655	27,148	32,219	27,302	27,867
Union	0	255,339	193,320	218,965	162,200	170,105
Total	0	374,564	285,940	324,466	249,765	260,377
Total Benefits (Current + Accrued)						
Executive	0	156,314	159,723	160,260	180,304	190,295
Management	0	327,580	345,059	378,177	418,812	452,549
Non-Union	0	206,454	209,313	236,727	271,429	287,062
Union	0	1,478,487	1,490,497	1,608,828	1,612,540	1,752,272
Total	0	2,168,835	2,204,592	2,383,993	2,483,086	2,682,178
Total Compensation (Salary, Wages, & Benefits)						
Executive	870,379	844,247	865,957	844,882	906,309	924,174
Management	1,788,641	1,744,282	1,829,512	1,964,607	2,062,177	2,143,098
Non-Union	1,243,261	1,087,025	1,057,394	1,188,230	1,322,402	1,397,993
Union	7,647,834	7,603,099	7,972,056	8,483,284	8,472,410	8,863,003
Total	11,550,114	11,278,653	11,724,920	12,481,004	12,763,298	13,328,268
Compensation - Average Yearly Base Wages						
Executive	132,731	137,587	141,247	148,508	145,201	146,776
Management	82,803	85,074	89,077	89,934	91,400	93,919
Non-Union	64,822	66,710	71,991	71,008	75,339	79,637
Union	57,065	58,882	59,175	60,720	61,213	63,337
Total	337,421	348,252	361,490	370,169	373,152	383,669
Compensation - Average Yearly Overtime						
Executive	0	0	0	0	0	0
Management	0	0	0	0	0	0
Non-Union	0	0	0	0	0	0
Union	2,544	6,952	7,839	10,034	7,627	7,164
Total	2,544	6,952	7,839	10,034	7,627	7,164
Compensation - Average Yearly Incentive Pay						
Executive	14,624	15,751	17,694	17,694	23,000	24,227
Management	0	0	0	0	0	0
Non-Union	0	0	0	0	0	0
Union	0	0	0	0	0	0
Total	14,624	15,751	17,694	17,694	23,000	24,227
Compensation - Average Yearly Benefits						
Executive	35,496	31,263	31,945	34,764	36,061	38,059
Management	22,411	19,671	20,706	21,439	23,293	25,142
Non-Union	17,929	15,640	17,768	17,666	19,457	20,578
Union	16,221	15,892	15,411	16,559	16,182	17,373
Total	92,057	82,467	85,829	90,427	94,993	101,152
Total Compensation	11,550,114	11,278,653	11,724,920	12,481,004	12,763,298	13,328,268
Total Compensation Capitalized (CGAAP)	5,324,014	3,621,377	3,536,039	4,430,940	4,383,044	
Total Compensation Charged to OM&A (CGAAP)	6,226,100	7,657,276	8,188,881	8,050,064	8,380,254	
Total Compensation Capitalized (MCGAAP)						3,680,642
Total Compensation Charged to OM&A (MCGAAP)						9,647,626

Consistent with the Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications dated June 28 2012, Thunder Bay Hydro has provided explanations (justifications provided for above in the Head Count discussion) for year-over-year variances.

Refer to in Exhibit 6, Tab 1, Schedule 2, Table 6-1.2 for annual contract and management increases.

2009 Board Approved to 2009 Actuals

Management

Change in FTE: (.035)

The Line Superintendent retired July 31, 2009 and the position was not filled until June 1, 2010 leaving a reduction in 2009 of (0.46) FTE. Contract services replaced the reduction in wages over this time period. A Lines Supervisor retired effective October 31, 2009. This position was replaced May 11, 2009 as the last day physically at work for the retiring Line Supervisor was June 26, 2009 leaving a net overlap of approximately +0.16 FTE.

Change in compensation: $9,056

Management/Non-Supervisory:

Change in FTE: (1.82)

The resignation of a Project Manager May 8, 2009 left the position vacant for 8 months for a reduction of (0.65 FTE); the deferral of the decision to increase complement in the Purchasing Department pending review and recommendation by the new Manager, Purchasing & Stores resulted in a reduction of (1 FTE). In addition to the above there was also a maternity leave in Safety & Training from November 4, 2009 to July 12, 2010, which was covered by the Human Resources & Safety Advisor leaving a reduction of (0.17 FTE) and increased Part-Time hours of 0.19 FTE and approximately (0.16 FTE) reduction in wages deferred or allocated to “non-wires”.

Change in Compensation: ($45,880)

Union:

Change in FTE: (8.20)

The 2009 Board approved budget did not reduce the FTEs for union staff hours that were part of the Smart Meter capital work. This reduction in FTE in 2009 for capital work for the Smart Meter project was (2.63 FTE) and compensation reduction of ($155,000).

Timing of the hiring of the new PLTs resulted in a reduction of (2.48 FTE). A total of 3 PLT apprentices were hired (2 on January 12, 2009 and 1 on April 20, 2009); 3 PLTs were hired (1 on January 5, 2009, 1 on January 9, 2009 and 1 on April 6, 2009). The System–Operator Apprentice was hired on February 23, 2009 and the Meter Apprentice was hired April 6, 2009 and then resigned on October 23, 2009.

The decision was made to contract out the Arrears/Vacancy work resulting in part-time hours FTE reduction of (1).

A staff member was promoted to the Management group effective May 11, 2009; one staff member went on LTD effective September 20, 2009 one staff member resigned October 23, 2009, a Customer Service Clerk retired June 30, 2009 all adding to a reduction in FTEs of (3.07). Partially offsetting these reductions is a part-time increase of 1.11 FTE.

Change in Compensation: $150,003

Although the FTE complement decreased from the 2009 Actuals to the 2009 Board Approved, the compensation actually increased due to the overtime budget being significantly under budgeted by $398,000. (See Exhibit 6, Tab 1, Schedule 2 for discussion of the OM&A).

2009 Actuals to 2010 Actuals

Management/Non-Supervisory:

Change in FTE: (1.42)

There was a reduction of (0.48) FTE as a result of a maternity leave in 2010. An additional reduction of (0.81) FTE was a result of a number of Engineering position vacancies during 2009 and 2010.

Change in Compensation: ($32,489)

Union:

Change in FTE: 3.69

There was an increase in 2010 FTE as a result of the following:

- Hiring of 3 PLT apprentices in Jan/Feb/Apr 2009, which resulted in an increase of 0.77 FTE
- Hiring of new PLT January 2009 for a net increase of 0.25
- Death of Fleet Maintenance Technician which was offset with replacement for a net decrease of (0.40)
- Retirement of PLT June 2010, decrease of (0.51)
- Retirement of Engineering Locate Coordinator January 2011, but last physical day April 23, 2010 offset by replacement for a net increase of 0.11.
- Retirement of Meter Technician October 2010, decrease of (0.21)
- Hiring of 2 PLT Apprentices in January 2010, increase of 1.96 (as part of succession/capital plan)
- Equipment Operator on Long Term Disability effective September 2009, decrease of (0.76)
- Movement of 3 PLT to Supervisors effective May, 2009, April, 2010 and November 2010, decrease of (1.15)
- Transfer of a Management Temporary position to Temporary Billing Clerk, increase 0.92
- Hiring of a Buyer, September 2010, increase of 0.29
- An increase in students of 1.42 FTE

- An increase of part-time Customer Service hours equating to a 0.47 FTE increase
- An increase of temporary union positions equating to a 0.5 FTE increase

Change in Compensation: $356,947

Compensation increased as a result of the increase in compliment, progressions relating to new hires and apprentices and overall wage increases.

2010 Actuals to 2011 Actuals

Executive:

Change in FTE: (.39)

The position of Vice President, Power Systems was vacant from July 1, 2011 to November 22, 2011.

Change in Compensation: ($21,613)

Management/Supervisory:

Change in FTE: 0.98

In 2011, in response to increased regulatory pressures and increased workload, Thunder Bay Hydro increased the supervisory complement in the Finance Division by 1 with the introduction of the position Supervisor, Business & Regulatory Affairs. This position was in place effective May 16, 2011. This would reflect an increase in the FTE of 0.64.

During the year the Purchasing manager retired and a replacement was hired for an overall complement increase of .20

A PLT Supervisor retired in October 2010 for a FTE decrease of (0.83)

Two PLT's were promoted to Supervisors in November 2010 and April 2010 for FTE increase of 1.2

One PLT Supervisor was promoted to Vice-President Power Systems for a FTE decrease of (0.11)

Change in Compensation: $101,977

Compensation increase is a result of overall complement increase, overall wage increases and progressions of new management staff.

<u>Management/Non-Supervisory:</u>

Change in FTE: 1.62

There was an increase of 0.04 FTE as a result of deferring smart meter wages of $9,000 in 2011 vs 2010.

Three vacant Engineering positions were filled throughout the year for a FTE increase of 1.93.

There was a maternity leave in the Health and Safety Department which was partially offset by a temporary position for an overall FTE increase of 0.27.

There was and FTE of (0.39) which was covered through OPA programs.

The net effect of the new position Supervisor, Business & Regulatory Affairs was an overall decrease of (0.12) between the hiring of the position's replacement and transfer to management/supervisory

Change in Compensation: $103,422

<u>Union:</u>

Change in FTE: 0.44

There was an increase in 2011 FTE as a result of the following:

- The retirement of a buyer having an effective last day worked on December 23, 2010, the position was not replaced until April 2010 for an overall net decrease of (0.80)

- There were 2 PLT and 1 Cashier retirements in June 2010, January 2011 and October 2010 for an overall FTE decrease of (1.63)
- 2 PLT's were promoted to Supervisors for a FTE decrease of (1.80)
- 3 PLT Apprentices were hired, one in January 2011 and two in June 2011 for an overall compliment increase of 2.13
- There was an overall increase in complement of 1.8 associated with the decrease in time spent on the Smart Meter Project
- A staff member was promoted to Manager of Customer Service in January 2011 for a net decrease of (0.88)
- A Temporary Billing Clerk was hired to compensate for time that regular billing staff were transitioning and testing TOU billing overall increase of 0.77
- Customer Service part time hours were increased to compensate for Full time Customer Service Clerk retirements that were not filled. This resulted in an overall increase of 1.03.

Change in Compensation: $392,897

This increase is a result of regular increases and progressions. In addition overtime increased in 2011. The largest increase was in capital to ensure projects were completed as required.

2011 Actuals to 2012 Bridge

<u>Executive:</u>

Change in FTE: 0.39

The position of Vice President, Power Systems was vacant from July 1, 2011 to November 22, 2011.

Change in Compensation: $41,383

Management/Supervisory:

Change in FTE: 0.34

In 2011, in response to increased regulatory pressures and increased workload, Thunder Bay Hydro increased the supervisory complement in the Finance Division by one with the introduction of the position Supervisor, Business & Regulatory Affairs. This position was in place effective May 16, 2011. 2012 would reflect a FTE of (.36) versus (0.64) in 2011. A Power systems technician was promoted to Supervisor for an increase in FTE of 1.

Change in Compensation: $56,935

Management/Non-Supervisory:

Change in FTE: 0.55

The AMI Data Systems Coordinator is no longer deferred as part of the Smart Meter project and therefore reflects an FTE equivalent increase of .53 for 2012.

Change in Compensation: $99,469

Union

Change in FTE: 2.49

In 2011 there was 1 retirement of a Metering Technician on December 30, 2011 that will decrease the 2012 complement by (1) FTE.

In 2012 there were 4 retirements that decreased the 2012 FTE compliment by (1.88) as follows:

- Payroll Clerk retired June 29, 2012
- 2 PLT; retirement date of October 8, 2012, last physical day June 28, 2012 and retirement date April 30, 2012;
- 1 System Operator retired May 31, 2012

In 2013 there will be 3 retirements that will decrease the 2012 FTE compliment by (0.71) as follows:

- Customer Service Clerk retiring January 10, 2013, but last physical day September 29, 2012
- Store Keeper retiring April 30, 2013 but last physical day October 5, 2012
- 1 PLT retirement date September 21, 2013 but last physical day October 26, 2012

In 2012 there is an increase of 0.84 FTE due to the full year impact of 2 Power Line Technicians hired in June 2011.

There were 4 Power Line Technician Apprentices and 1 Power Line Technician hired January 2012 for an increase in FTE of 5.

One Power Line Technician moved to a Supervisory position in January 2012 and 1 was seconded by the union on October 31, 2011 for an overall FTE decrease of (1.83).

An overall increase of 1 FTE due to the reduction of hours spent by unionized staff on the Smart Meter Capital project.

There was an overall increase in Part Time hours of 0.6 mainly due to the following:

- Increase in Engineering Junior Drafter position of .31
- Increase of 0.29 for a part time Power Systems clerk to cover an extended medical leave
- Increase in part time Store Keeper hours of .22 due to the replacement of the full time retired Store Keeper
- Reduction in hours to a number of miscellaneous part time positions

Change in Compensation: ($14,586)

2012 Bridge to 2013 Test

<u>Union</u>

Change in FTE: 1.21

In 2012 there were 4 retirements that decreased the 2013 FTE compliment by (2.17) as follows:

- Payroll Clerk retired June 29, 2012
- 2 PLT; retirement date of October 8, 2012, last physical day June 28, 2012 and retirement date April 30, 2012;
- 1 System Operator retired May 31, 2012

In 2013 there will be 3 retirements that will decrease the 2013 FTE compliment by (2.29) as follows:

- Customer Service Clerk retiring January 10, 2013, but last physical day September 29, 2012
- Store Keeper retiring April 30, 2013 but last physical day October 5, 2012
- 1 PLT retirement date September 21, 2013 but last physical day October 26, 2012

In 2013 there is a new position budgeted in Customer Service in response to the anticipated increase in workload due to the Green Energy Act. There will be an additional 6 new Power Line Technician apprentices and 1 Station apprentice hired to address upcoming retirements and increase in capital work. All new hires are anticipated to begin January 1, 2013. Due to timing of hiring and retirements/progressions there was an overall decrease of (1.15) FTE anticipated for 2013. Part time FTE will decrease overall by (1.33) due to a reduction of hours to a number of positions.

Change in Compensation: $250,861

Increase in compensation due to new complement, regular wage increases and progressions of apprentices and new hires.

Workforce Planning

Thunder Bay Hydro's core business is the construction, operation and maintenance of the local distribution system. Skilled trades' resources and technical staff are required in order to meet Thunder Bay Hydro's responsibilities to provide safe and reliable service to customers and to maintain the OEB Service Quality Levels.

Thunder Bay Hydro faces increases in workload for the following reasons:

- Thunder Bay Hydro has increased the amount of capital work it performs. The Thunder Bay Hydro Asset Management Plan projects future increases in replacement of aged infrastructure will be required over the next 20 years.
- Demand work continues to increase as we strive to maintain Thunder Bay Hydro current system.
- The City of Thunder Bay initiated plant relocations have continued to increase. With the City's infrastructure aging as well, this is expected to continue and require upgrades in the coming years.

Thunder Bay Hydro's skilled work force is aging, and significant retirement levels are forecasted in the trades and trades supervision over the next 5 to 15 years. This is commonplace in Thunder Bay Hydro's industry resulting in limited availability in required skills. This also raises the concern of existing staff obtaining employment elsewhere with the opportunities available to them.

To project staff numbers, Thunder Bay Hydro considers loss of personnel due to retirement, internal advancement, and opportunities with other employers. Thunder Bay Hydro also takes into account the likelihood of attracting qualified staff as replacements.

Thunder Bay Hydro demographics alone clearly demonstrate that Thunder Bay Hydro must plan on replacing significant numbers of trades staff over the coming years if it is to maintain sufficient skilled trades people to manage Thunder Bay Hydro workload. This is reflected in Table 4-2.12 below:

Table 4-2.12 – Number of Skilled Trades People Required

Classification	Current Complement	Eligible to Retire in 5 years	Eligible to Retire in 10 years
Trades Supervisor	8	4	4
Powerline Tech	44	10	17
Metering Tech	2	1	1
System Operator	7	1	2
Station Electrician	2	0	1
P&C Technician	1	0	1
Total	64	16	26

Trades and technical staff such as the Metering Technicians, System Control Operators and Station Electricians work within small workgroups. The loss of a single staff member in these departments represents a significant percentage of that labour force which has a negative impact on workload and shift coverage.

One possible option for Thunder Bay Hydro to replenish and expand its trades staff workforce is to recruit, as required, fully qualified journeypersons and add them immediately to the workforce with modest amounts of orientation and/or training. The availability of fully qualified journeypersons in these fields is very sparse and decreasing annually. Therefore Thunder Bay Hydro's ability to attract certified trades people, especially in the local market, is unlikely.

In response to the tight supply in the labour market and the operational requirements for additional staff, Thunder Bay Hydro has introduced strategic hiring in the areas impacted by the demographic challenges facing the electrical industry, through the use of apprentice programs and the strategic hiring of technical staff.

The advantages of hiring and training apprentices and new technical staff include; a typically younger workforce age, consistency in training, and learning and training on the system for which they will ultimately be responsible. Other utilities in the province are experiencing similar challenges and have also come to the conclusion that the hiring and training of apprentices is the best option.

Besides the obvious benefit of revitalizing the workforce, new employees offer many intangible benefits including improved staff morale and improved labour relations through demonstrating an investment in the future of the workgroups within the company.

Apprentice Program Hiring:

To graduate from an apprentice program requires 5 years of on the job training and schooling. Apprentices therefore must be hired in advance of qualified tradesperson retirements/requirements to allow time for the apprentices to complete their training if Thunder Bay Hydro is to maintain the necessary level of qualified labour. This requirement, by default, results in increases to complement.

Powerline Technician Apprentices:

- In both 2011 and 2012, Thunder Bay Hydro hired Powerline Technician Apprentices to address pending retirements and increased capital spending. Going forward, Thunder Bay Hydro plans to hire an additional 6 Powerline Technician apprentices in 2013 (2 for pending retirements, 4 for increase in capital spending).

Station Maintenance Electrician Apprentice:

- Power Systems is requesting an additional Station Maintenance Electrician Apprentice in 2013 to account for an increase in workload.

Efficiencies achieved since the 2009 Cost of Service Application:

Thunder Bay Hydro continually strives to improve efficiencies across all departments within the Corporation. In regards to workforce planning and compensation, the following efficiencies have been gained since Thunder Bay Hydro's last Cost of Service Application and have also been included as part of its current Application:

- New salary schedules for union employees hired after May 1, 2010
- Variable percentage wage increases for unionized employees depending on wage group
- Vacation entitlement for unionized staff capped at five weeks applicable for all new staff hired after May 1, 2010 (previously seven weeks)

- Starting in 2010, all new trades apprentices must pay for their own training and incidentals (transportation, accommodation, meals, etc.) which were previously company paid
- Increased student funding achieved via government programs

Change in Benefits:

In 2011, OMERS released a 3-year plan indicating approximately 1% per year increase in OMERS premiums beginning in 2012. The expected increase for 2013 has been confirmed and can be viewed on the OMERS website. Below is a copy of the applicable sections of the web release.

News

OMERS 2013 Contribution Rates and Plan Changes Announced

July 06, 2012

OMERS Sponsors Corporation (SC), which represents active and retired members and employers, approved two plan changes in a meeting on June 28, 2012:

- Contribution rate increases were set for 2013 - the third increase as part of a three-year strategy announced in 2010; and
- A cap on contributory earnings, equal to seven times the CPP earnings limit (Year's Maximum Pensionable Earnings or YMPE).

In addition to setting the contribution rates for 2013, the SC approved a new method for allocating contribution rates in the future. These changes do not affect OMERS retired members, deferred members, or survivors.

As well, the December 31, 2011 valuations for the OMERS Primary Pension Plan (OMERS Plan) and the OMERS Supplemental Plan for Police, Firefighters and Paramedics (Supplemental Plan) will be filed.

Contribution rates

Contribution rate changes for the OMERS Plan are effective with the first full pay in 2013.

		2012	2013
Normal retirement age 65 members	On earnings up to CPP earnings limit*	8.3%	9.0%
	On earnings over CPP earnings limit*	12.8%	14.6%
Normal retirement age 60 members	On earnings up to CPP earnings limit*	9.4%	9.3%
	On earnings over CPP earnings limit*	13.9%	15.9%

**The CPP earnings limit in 2012 is $50,100; the limit in 2013 will be higher. OMERS members pay a lower rate on earnings up to the YMPE because OMERS and the CPP are designed to work together to provide pension benefits. Contributions are tax deductible which lessens the net impact on Plan members.*

In 2010, OMERS announced a three-year plan to increase contribution rates. The contribution rate increases set for 2013, are the third increase.

- A flat 1% contribution rate increase per side was implemented in 2011.
- In 2012, the average increase in contribution rates was 1% per side, but the actual increase in each of the four component rates showed more variation.
- Also in 2012, the SC conducted a comprehensive review of the principles for setting contribution rates, leading to the 2013 rates above.
- The rates for 2013 affect members differently at various earnings levels and normal retirement age groups (65 and 60); however, the increase averages out to be 0.9% for members and employers.
- These rates will provide the OMERS Plan with the total contributions required to fund the OMERS Plan until the next actuarial filing.

Examples of biweekly contribution increases, based on 26 pay periods

Normal retirement age 65

	Contributions*		Difference per pay period	
Total annual				

earnings example	2012	2013	Gross**	Net**
$40,000	$127.69	$138.46	$10.77	$8.17
$65,000	$233.28	$257.09	$23.81	$16.39

Normal retirement age 60

	Contributions*		Difference per pay period	
Total annual earnings example	2012	2013	Gross**	Net**
$65,000	$260.79	$270.32	$9.53	$6.56
$90,000	$394.44	$423.20	$28.76	$16.28

**This calculation uses the 2012 YMPE ($50,100).*
***Net differences after tax are based on 2012 Federal and Ontario marginal tax rates and assume the member has taxable income equal to the annual earnings shown.*

These rate increases are intended to be temporary until the deficit is eliminated, and are part of a long-term strategy to return the OMERS Plan to full funding.

New method for allocating contribution rates

- Starting 2014, a new method for allocating any contribution rate adjustments for the OMERS Plan will be used.
- The new method strikes a balance for different member groups among the various contribution rate setting principles. These principles include transparency, limited volatility, value for money, pooling, limited complexity and cost effectiveness.

Cap on contributory earnings

This change will cap a member's earnings for pension purposes and it will only affect members earning over seven times the CPP earnings limit. (If the cap were in effect for 2012 this would be 7 x $50,100 or $350,700.)

This change applies to the OMERS Plan, the Retirement Compensation Arrangement (RCA) for the OMERS Plan, and the Supplemental Plan. This cap is in addition to the existing cap on contributory earnings (i.e., for incentive pay).

The effective date of the cap on contributory earnings is:

- January 1, 2016 for members enrolled before January 1, 2014, and
- January 1, 2014 for members enrolled on/after January 1, 2014.

Details for OMERS employers will be posted in the *Employer Administration Manual*.

This increase in OMERS pension costs has been included in the cost of current benefits in this application. The increases for 2012 and 2013 are compounded by general salary increases, outlined in Table 4-2.13 below.

Table 4-2.13 -Post-Retirement Benefits - Premiums

OMERS Premiums Paid	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test CGAAP & MCGAAP
	$ 410,660	$ 432,082	$ 446,511	$ 527,663	$ 725,637

Post-Retirement Benefits – Liability:

Thunder Bay Hydro has provided post-retirement benefits accounting information as required and has included the change in Post-Retirement expense for 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and 2013 Test Year, in Table 4-2.14 below.

Thunder Bay Hydro pays certain health, dental, and life insurance benefits on behalf of its retired employees. Actual premiums paid for 2009 Actual, 2010 Actual, 2011 Actual, 2011 Actual, 2012 Bridge Year, and 2013 Test Year, are shown in Table 4-2.14 below.

Table 4-2.14: Post-Retirement Benefit Information

Post Retirement Benefits	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test CGAAP & MCGGAP
Premiums & Expenses Paid *	$ 155,458	$ 143,500	$ 241,518	$ 62,766	$ 110,466
Change in Accrued Liability	$ 87,433	$ 49,617	$ (40,813)	$ 97,996	$ 73,564
Total Post-Employment Benefit Expense	$ 242,892	$ 193,117	$ 200,705	$ 160,763	$ 184,030

* 2012 Estimate based on projected actuals; 2013 based on 2012 estimate plus 5%

The most recent actuarial report for 2012 is attached as Appendix 4-C.

Thunder Bay Hydro's Performance Management Program:

<u>Management/Professional/Supervisory/Administrative Employees</u>

Performance management is a shared process that includes input from the employee and the supervisor. It is the collaborative process that facilitates the link between the employee's job duties and expectations and the organization's mission, vision, values and corporate strategic objectives.

Thunder Bay Hydro's performance management program clarifies job responsibilities, performance and competency standards and objectives between the employee and supervisor; provides for regular feedback to employees about their performance; and establishes employee developmental needs and encourages continuous learning.

The performance management system aligns employee performance plans with the attainment of strategic business objectives and goals, as well as the opportunity to cultivate a system-wide, long-term view of the organization.

For managers, the performance management system improves operations in the department; facilitates communications with employees regarding performance strengths and weaknesses; facilitates the development of goals; aids decision making regarding promotions/reassignments and provides for training/development plans.

For employees, the performance management system provides an opportunity to receive feedback regarding their work performance. The system can assist employees in identifying where to concentrate self-development efforts and in learning about possible career paths that may be available to them in the organization. This feedback loop also improves productivity, quality of service to customers and enhances employee motivation and commitment.

<u>Unionized Employees</u>

All unionized employees have a formal performance review on an annual basis to discuss their performance with their supervisors.

Goals and objectives are agreed to for the next 6 to 12-month review period (dependent on the objectives and the expected deliverables) in areas that require improvement to meet job or performance targets.

SHARED SERVICES AND CORPORATE COST ALLOCATION

Introduction:

Thunder Bay Hydro Corporation (TBHC) is the parent company for three affiliates; Thunder Bay Renewable Power Incorporated (TBRPI), a generation company; Thunder Bay Hydro Electricity Distribution Inc., (Thunder Bay Hydro) the Distribution Company; and Thunder Bay Hydro Utility Services Inc. (TBHUSI), a back office services company. Competitive meter service provider (MSP) services are also provided within TBHUSI to northern commercial and industrial customers. Thunder Bay Hydro provides certain services to its various affiliates. Thunder Bay Hydro recovers revenues from TBRPI and TBHUSI in respect of the services it provides, and these revenues are as per the Affiliate Services Agreement in Appendix 4-A.

Related party transactions with the Corporation of the City of Thunder Bay (City of Thunder Bay) include Thunder Bay Hydro's payment of property taxes, water and sewer charges, telephone charges and the City of Thunder Bay's payment to Thunder Bay Hydro for electricity bills. The foregoing involves non-discretionary transactions. Thunder Bay Hydro does not have a Services Agreement with the City of Thunder Bay.

Corporate Cost Allocation is defined as an allocation of costs for corporate and miscellaneous shared services from the parent company TBHC to Thunder Bay Hydro and vice versa. Thunder Bay Hydro confirms that there are no sharing of costs between TBHC and Thunder Bay Hydro.

Services Provided by Thunder Bay Hydro to TBHUSI

TBHUSI is a back office services company that provides wholesale settlement, EBT, meter reading, MV90, customer information system, bill production and mailing, after hour's system control, related ISD services and conservation programming exclusively to the small LDCs in Northwestern Ontario. Also, TBHUSI offers AMI services to the LDCs which includes synchronization of the meter data across the AMI, ODS and MDM/R systems, business process development and management, licensing and hardware and software support. The services are provided to regional LDCs only and are not marketed or promoted to a larger group. The

arrangements with the regional LDCs allows for overall efficiencies to be gained by sharing of expertise and excess capacity. Essentially, the smaller utilities contracts with TBHUSI for the primary reason of being remotely hosted on Thunder Bay Hydro's computer systems for their use of hardware and software for Customer Information Systems, Financials, remote meter reading, etc.

For the most part, the Northern Ontario utilities perform their own work with their own staff on the computer systems through remote access with minimal assistance from Thunder Bay Hydro staff. Thunder Bay Hydro staff monitors the MV90 and wholesale settlement systems to make sure utility meter data passes VEE rules prior to transmission to the billing system. Thunder Bay Hydro staff also process EBT transactions, make billing collection calls, receive after hour outage calls on behalf of and for regional LDCs and provide ISD support related to the information systems being used.

TBHUSI is also registered as a Meter Service Provider with the IESO to provide metering related services to Northwestern Ontario commercial and industrial customers. TBHUSI contracts with Thunder Bay Hydro for staff and equipment to carry out this work and bills TBHUSI based on the Service Agreement. This work includes the following:

1. Meter Service Provider Services, which includes maintenance of equipment and information for Wholesale meters on the IESO controlled grid
2. MV90 Services, which includes remote meter reading services for interval customers
3. Engineering Services, which includes the design and registration of new metering installations

Services Provided By Thunder Bay Hydro to TBRPI

TBRPI is a wholly-owned subsidiary company of TBHC which operates a landfill gas generation plant under a 20-year contract with the OPA effective August, 2010. TBRPI receives services from Thunder Bay Hydro on a fully-allocated basis which is calculated annually and charged on a fixed monthly basis.

Services Provided By Thunder Bay Hydro to TBHC

TBHC owns 100% of Thunder Bay Hydro, TBHUSI, and TBRPI. A service agreement has been signed between TBHC and Thunder Bay Hydro in 2012 covering TBHC Board Member remuneration reimbursements. Thunder Bay Hydro is reimbursed for TBHC Board remuneration disbursements.

Below are Tables 4-2.15 – 4-2.19 replicated from the Appendix Chapter 2-N that provide additional detail on the shared services and corporate cost allocation for the Historical, Bridge and Test Years.

Table 4-2.15 - Shared Serivces

Year: 2009 Actual

Shared Services					
Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	Conservation & Demand Mgmt, Utility Billing Services, Meter Services, IT Services	Cost + Greater of Bank Prime OR Approved ROE (3.75% EB-2008-0245)	$165,797	$159,804
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Renewable Power Incorporated	Corporate/Administrative Costs	Fully Allocated Costs	$128,511	$128,511
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Energy Services Inc.	Administrative Costs	Cost + Greater of Bank Prime OR Approved ROE (3.75% EB-2008-0245)	$47,442	$45,727

Corporate Cost Allocation					
Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	N/A	N/A	N/A	N/A
Thunder Bay Hydro Utility Services Inc.	Thunder Bay Hydro Electricity Distribution Inc.	N/A	N/A	N/A	N/A

Table 4-2.16 - Shared Serivces

Year: 2010 Actual

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	Conservation & Demand Mgmt, Utility Billing Services, Meter Services, IT Services	Cost + Greater of Bank Prime OR Approved ROE (3.75% EB-2008-0245)	$231,877	$223,496
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Renewable Power Incorporated	Corporate/Administrative Costs	Fully Allocated Costs	$83,947	$83,947
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Energy Services Inc.	Administrative Costs	Cost + Greater of Bank Prime OR Approved ROE (3.75% EB-2008-0245)	$1,271	$1,225

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	N/A	N/A	N/A	N/A
Thunder Bay Hydro Utility Services Inc.	Thunder Bay Hydro Electricity Distribution Inc.	N/A	N/A	N/A	N/A

Table 4-2.17 - Shared Serivces

Year: 2011 Actual

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	Conservation & Demand Mgmt, Utility Billing Services, Meter Services, IT Services	Cost + Greater of Bank Prime OR Approved ROE (3.75% EB-2008-0245)	$273,837	$263,939
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Corp.	Board Honourarium	Fully Allocated Costs	$1,625	$1,625
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Renewable Power Incorporated	Corporate/Administrative Costs	Fully Allocated Costs	$84,101	$84,101

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	N/A	N/A	N/A	N/A
Thunder Bay Hydro Utility Services Inc.	Thunder Bay Hydro Electricity Distribution Inc.	N/A	N/A	N/A	N/A

Table 4-2.18 - Shared Serivces

Year: 2012 Bridge Year

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	Conservation & Demand Mgmt, Utility Billing Services, Meter Services, IT Services	Cost + Greater of Bank Prime OR Approved ROE (3.75% EB-2008-0245)	$201,226	$193,953
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Corp.	Board Honourarium	Fully Allocated Costs	$1,500	$1,500
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Renewable Power Incorporated	Corporate/Administrative Costs	Fully Allocated Costs	$86,720	$86,720

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	N/A	N/A	N/A	N/A
Thunder Bay Hydro Utility Services Inc.	Thunder Bay Hydro Electricity Distribution Inc.	N/A	N/A	N/A	N/A

Table 4-2.19 - Shared Serivces

Year: 2013 Test Year

Shared Services

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service
From	To			$	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	Conservation & Demand Mgmt, Utility Billing Services, Meter Services, IT Services	Cost + Greater of Bank Prime OR Approved ROE (3.75% EB-2008-0245)	$253,703	$244,533
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Corp.	Board Honourarium	Fully Allocated Costs	$1,500	$1,500
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Renewable Power Incorporated	Corporate/Administrative Costs	Fully Allocated Costs	$88,895	$88,895

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	N/A	N/A	N/A	N/A
Thunder Bay Hydro Utility Services Inc.	Thunder Bay Hydro Electricity Distribution Inc.	N/A	N/A	N/A	N/A

Pricing Methodology

As seen in the tables above, Thunder Bay Hydro has two pricing methodologies: (1) fully allocated costs; and (2) cost plus the greater of the bank prime rate or the most recent Board-Approved ROE (which is 3.75% as per EB-2008-0245) in the 2009 Cost of Service Application. The rationale for the two methodologies is based on whether a market exists or not for the services being offered as defined in the RSC 2.3.3, which then dictates how much can be charged. (As previously mentioned Thunder Bay Hydro only provides services and does not receive services from its affiliates.) Thunder Bay Hydro believes that the services it provides its affiliates, no competitive market exists. Thus, the Affiliate Relationship Code (ARC") states in 2.3.4.2

> "*Where a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility sells to an affiliate, the utility shall charge no less than its fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost shall include a return on the utility's invested capital. The return on invested capital shall be no less than the utility's approved weighted average cost of capital."*

TBHC is 100% owned by the shareholder, The City of Thunder Bay. Thunder Bay Hydro charges TBRPI and TBHC at fully-allocated cost as the transactions occur all within the TBHC umbrella. However, TBHUSI provides services to other utilities outside of this umbrella, thus, charging fully-allocated costs plus a markup which is the greater of the bank prime rate or Thunder Bay Hydro's ROE of 3.75%.

Outlined in Table 4-2.20, is a variance analysis of the Shared Services as requested in the Chapter 2 Filing Requirements:

Table 4-2.20 - Shared Serivces and Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methdology	A	B	C	Variance C - A	Variance C - B
				2009 Board Approved	2011 Actuals	2013 Test Year	Test Year vs. 2009 BA	Test Year vs. 2011 Actuals
From	To			Price for the Service	Price for the Service	Price for the Service	Price for the Service	Price for the Service
				$	$	$	$	$
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Utility Services Inc.	Conservation & Demand Mgmt, Utility Billing Services, Meter Services, IT Services	Cost + Greater of Bank Prime OR Approved ROE (3.75% EB-2008-0245)	$63,000	$273,837	$253,703	$190,703	-$20,134
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Corp.	Board Honourarium	Fully Allocated Costs		$1,625	$1,500	$1,500	-$125
Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Renewable Power Incorporated	Corporate/Administrative Costs	Fully Allocated Costs		$84,101	$88,895	$88,895	$4,794

With a materiality threshold of $85,000, there are two variances in the Table above between the Test and Board-Approved year. First, a favourable variance of $190,703 exists between Thunder Bay Hydro and TBHUSI due to providing CDM and smart meter billing services and a reallocation of IT costs that were not included in the 2009 Board Approved. Second, there is a $88,895 favourable variance between Thunder Bay Hydro and TBRPI due to the fact that shared services were not budgeted for in the 2009 Cost of Service Application as the scope of the services to be provided were not yet known during the application process.

PURCHASE OF PRODUCTS AND SERVICES FROM NON-AFFILIATES:

Thunder Bay Hydro purchases many services and products from third parties. Tables 4.2.21, 4-2.22 and 4-2.23 disclose the expenditures for vendors whose annual products purchased or services rendered exceeded $85,000 per year for 2009, 2010 and 2011. Included in the tables are a listing of the supplier's names, service description, and pricing methodology.

A copy of Thunder Bay Hydro's procurement policy has been provided in Appendix 4-B which Thunder Bay Hydro has complied with in the past and will continue to do so.

Table 4-2.21 - 2009 Non-Affiliate Suppliers

VENDOR'S NUMBER	VENDOR'S NAME	SERVICES DESCRIPTION	PRICE METHODOLOGY	DOLLAR AMOUNT
1381	Olameter	Meter Reading & Collection Services	Single Source	$762,835
783	Cambell Trucking & Backhoe	T06-09 - Blanket Purchase Order Clearing Power Lines Free of Trees T09-31 - Blanket Purchase Order To Cover all Cost Labour & Equipment for Line Clearing Work Which Primarily Involves the Cutting & Removal of Tree Growth In & Around Energized Lines.	Competive Bid Process	$634,702
2474	LTL Directional Drilling Services	T09-35 & T09-41 Blanket Purchase Order to cover all Cost Of Labour, Material & Equipment to Provide Directional Boring Services as required	Single Source	$409,285
515	Park Electric	P09-05 - Blanket Purchase Order to cover all Cost of Labour & Material to Supply & Install Lighting & Water Heaters retrofits P09-12 - to Provide Electrical work in the City of Thunder Bay	Competive Bid Process	$390,913
1943	Marvac Industrial Electrical Ltd.	T09-07 - Blanket Purchase Order for Pole Setting, Hauling, Framing, & Converting High & Low Voltage Power Lines	Competive Bid Process	$376,161
1484	City of Thunder Bay - Reality Services	Rental of Office Space	Negogiated	$305,302
692	Tbaytel	Communication Services	Single Source	$266,645
26	Altec Industries	T08-20 - 1 Only Single Axle 4 x 2 Wheel Drive, Two Men Convential Cab - Tilt Front, Derrick Digger Truck	Competive Bid Process	$266,196
1314	Hydro One Networks	T08-76 & T09-40 Blanket Purchase Orders for Construction & Metering Upgrades, Commissioning Work for Port Arthur TS, Revenue Metering Upgrades Port Arthur TS	Single Source	$210,804
2237	Mearie Management Inc.	Basic Life Insurance Premiums	Sole Source	$192,816
2350	Advantage Electric	T09-07 - Blanket Purchase Order for Pole Setting, Hauling, Framing, & Converting High & Low Voltage Power Lines	Competive Bid Process	$156,277
2326	Elster Metering	Purchase of Smart Meters	Competive Bid Process	$155,198
2837	Hydro One Networks	Wholesale meter upgrades	Single Source	$149,000
259	Allen F Equipment Rental	T08-19 -Single Bucket Truck	Competive Bid Process	$132,798
2544	CDW Canada Inc	Various Purchases by Tender,Quotes Computer - Hardware & Software Purchases - Hardware Mtce	Competive Bid Process, Sole Source & Single Source	$122,661
2494	POSI-Plus Ontario Inc.	T09-10 - Single International Cab & Chassis	Competive Bid Process	$104,004
53	Badani Motors Ltd	T09-04 - Two 1/2 Ton Trucks - One 3/4 Ton Truck	Competive Bid Process	$94,563
1221	Timberland Equipment Rental	T09-09 - New Puller/Tensioner Machine	Single Source	$86,330

Table 4-2.22 - 2010 Non-Affiliate Suppliers

VENDOR'S NUMBER	VENDOR'S NAME	SERVICES DESCRIPTION	PRICE METHODOLOGY	DOLLAR AMOUNT
783	Campbell Trucking & Backhoe	T09-31 Blanket Purchase Order to cover all costs, labour & equipment for line clearing work	Competive Bid Process	$624,225
		T07-65 Blanket Purchase order covers all cost for equipment rental services		
		Miscellaneous Equipment rental & other services to remove pole butts	Single Source	
2494	POSI-PLUS Ontario Inc.	T09-10 New double bucket truck, single axle, 6 x 4 wheel drive etc.	Competive Bid Process	$594,683
		T10-01 New double bucket truck,single axle, 6 X 4 wheel drive etc.	Competive Bid Process	
		Misc repairs truck #3	Single Source	
2837	Hydro One Networks	Wholesale meter upgrades	Single Source	$519,977
515	Park Electric	T09-12 Blanket Purchase order to cover all costs to provide electrical work	Competive Bid Process	$400,842
692	Tbaytel	Communication Services	Single Source	$329,231
1484	City of Thunder Bay-Reality Services	Rental of Office Space	Negogiated	$302,036
1314	Hydro One Networks	T09-40 Blanket Purchase Order to cover construction & commissioning work	Single Source	$275,123
		T08-76 Revenue metering upgrades		
2474	LTL Directional Drilling Services	T09-41 Blanket Purchase Order to cover all costs, labour, material & equipment for Directional Boring Services on an on-call basis	Competive Bid Process	$254,037
		To supply & install Conduit below sidewalk on Miles & Archibald St	Single Source	
		Duct installation work County Park	Single Source	
2809	Algal Engineering	P09-22 Blanket Purchase Order covers all costs for Electrical distribution system design Services	Competive Bid Process	$246,955
2237	Mearie Management Inc.	Basic Life Insurance	Sole Source	$202,678
1436	LTL Contracting	T07-37 Blanket Purchase Order to cover all costs for labour & equipment for vacuum excavation	Competive Bid Process	$194,443
1381	Olameter	07-32 Metering reading & collecting services	Single Source	$118,457
2193	Kinetiq Canada	T09-67 Blanket Purchase Order covers the period January 1, 2010 to December 31, 2010 for Operational Data Store Smart Metering	Single Source	$106,904
27	Altec Industries	T10-11 One new 37 ft Single bucket truck	Competive Bid Process	$101,811
1826	Global Rental Canada	T09-21 Rental of one single bucket truck	Single Source	$88,124
		Q10-I Rental of one Altec mount digger derrick	Single Source	
1154	Wildon Wiring Limited	T07-36 Blanket Purchase Order to cover all costs for labour & equipment for Rock Drilling Services	Competive Bid Process	$87,323
		T07-64 Blanket Purchase Order to cover all costs for the rental of an Off-Road Track Machine to complete with operator on an on-call basis		
		Q10-H - Blanket Purchase order to cover all costs for the rental of two Off-Road Track Machines		
		Miscellanous equipment rentals		

Table 4-2.23. - 2011 Non-Affiliate Suppliers

VENDOR'S NUMBER	VENDOR'S NAME	SERVICES DESCRIPTION	PRICE METHODOLOGY	DOLLAR AMOUNT
783	Campbell Trucking & Backhoe	T07-65 - Blanket Purchase Order to cover all costs for labour & equipment rental services	Competitive Bid Process	$593,879
		T09-31- Blanket Purchase Order to cover all costs for labour & equipment for line clearing work		
		Miscellanous services for labour & material		
692	Tbaytel	Communication Services	Single Source	$360,309
2350	Advantage Electric	T09-07 - Blanket Purchase Order for Pole Setting, Hauling, Framing, & Converting High & Low Voltage Power Lines	Competitive Bid Process	$352,532
2474	LTL Directional Drilling Services	T09-41 - Blanket Purchase Order covers labour, material & equipment to provide Directional Boring Services	Single Source	$325,077
		Miscellanous services for labour & material		
1484	City of Thunder Bay-Reality Services	Rental of Office Space	Negogiated	$310,900
1436	LTL Contracting	T07-37 - Blanket Purchase Order to cover all costs for labour & equipment to provide Vaccum Excavation Services		$273,038
1826	Global Rental Canada	Purchase Altec Derrick Digger	Single Source	$201,700
		Rental of Altec Derrick Diggers	Single Source	
2243	The Mearie Group	Basic Life Insurance	Sole Source	$161,853
757	Nortrax	T11-16 - One New 310 SJ Backhole Loader plus Warranty & Options Less Trade -In	Competitive Bid Process	$114,479
		Fleet Maintenance on Bucket Tilter Cylinder	Single Source	
2193	Kinetiq Canada	T09-67 - Blanket Purchase Order to cover all costs for operational data store (smart metering)	Single Source	$110,199
2237	Mearie Management Inc.	Basic Life Insurance	Single Source	$101,634
2953	MWG Apparel Group	P10-57 - Blanket Purchase Order to cover the supply of flame resistant (FR) uniforms	Single Source	$100,010
2544	CDW Canada Inc.	Q11-77 - Computer - PC Hardware Purchase	Competitive Bid Process	$99,439
		T-70 - Computer PC - Software Purchase	Competitive Bid Process	
		Q11-49A - Computer -PC Hardware Maintenance	Competitive Bid Process	
		Q11-59 - Blanket Purchase Order to cover all costs & Shipping for Lexmark toner, Cartridges photoconductor kits & maintenace kits for Lexmark W830	Competitive Bid Process	
		Q11- 38 - Computer-PC Hardware Maintenance	Competitive Bid Process	
		Q11-33 - Computer -PC Software Purchase	Competitive Bid Process	
		Q11- 36 Computer -PC - Hardware Maintenance	Competitive Bid Process	
		T11-21 - Computer PC - Hardware Purchase - Lenovo Thinkpad T520	Competitive Bid Process	
		Q-10-64 - Computer PC - Hardware Purchase - and Mtce Hardware ordered in 2010 - received in 2011	Competitive Bid Process	
		Q10-66 - Computer PC - Hardware Purchase on 2010 received in 2011	Single Source	
		Miscellanous Computer -PC Hardware Purchase, and Mtce Hardware	Single Source	
373	Lakehead Motors	T11-23 One new 3/4 ton, 4 x 4 , 4 door crew cab Truck with 8 ft box P.O. 110146	Competitive Bid Price	$91,152
		T11-11 - One new 3/4 ton, 4 x 4, 4 door crew cab P.O. # 110092	Competitive Bid Price	
		T11-11 - One new 3/4 ton, 4 x 4, 4 door crew cab P.O. # 110091	Competitive Bid Price	

DEPRECIATION, AMORTIZATION AND DEPLETION

Depreciation on capital assets is calculated as follows:

- Thunder Bay Hydro uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools. Depreciation is calculated on a straight line basis over the estimated remaining useful life of the assets. Depreciation commences when the asset has been put in service. Per CGAAP 3061.28 "*Amortization should be recognized in a rational and systematic manner appropriate to the nature of an item of property, plant and equipment with a limited life and its use by the enterprise*." As a result, Thunder Bay Hydro depreciated an item of PP&E when the asset was available for use.

- It is Thunder Bay Hydro's depreciation policy to commence depreciation when the asset has been put into service; however, the half-year rule has been used for the accounting for depreciation expense for this rate application for both the 2012 Bridge and 2013 Test Years. This basis was used as it should approximate the actual impact to depreciation.

- Depreciation rates for 2009-2013 CGAAP are in line with rates set out in the APH. Depreciation rates for 2013 MGCAAP are in line with the Kinectrics Study.

- Refer to MCGAAP – Impact on Depreciation for review of changes implemented for 2013 Test Year in Exhibit 4, Tab 4, Schedule 2.

Table 4-2.24, Summary of Amortization Expense for 2009-2013 is below

Table 4-2.24 – Summary of Amortization Expense for 2009 to 2013

Account	Description	2009 CGAAP Amortization Expense	2010 CGAAP Amortization Expense	2011 CGAAP Amortization Expense	2012 CGAAP Bridge Amortization Expense	2013 CGAAP Test Amortization Expense	2013 MCGAAP Test Amortization Expense
1611	Computer Software (Formally known as Account 1925)	65,006	30,321	20,824	93,245	97,865	51,926
1612	Land Rights (Formally known as Account 1906)	-	-	-	-		
1805	Land	-	-	-	-		-
1808	Garage	-	-	-	-	25,250	25,250
1808	Buildings	71,842	72,044	72,044	72,044	72,044	72,044
1810	Leasehold Improvements	6	17	423	4,004	8,399	8,399
1820	Distribution Station Equipment - ARO	-	-	-			7,386
1820	Distribution Station Equipment Normally Primary	168,641	168,820	169,361	169,361	169,361	319,827
1825	Storage Battery Equipment	-	-	-	-		
1830	Poles, Towers & Fixtures	742,565	929,376	995,308	1,050,123	1,115,044	727,173
1835	Overhead Conductors & Devices	1,085,345	1,143,954	1,203,746	1,236,676	1,302,012	455,881
1840	Underground Conduit	370,587	370,423	410,768	406,911	411,032	107,946
1845	Underground Conductors & Devices	441,441	467,616	464,959	480,425	504,694	355,182
1850	Line Transformers	797,794	991,351	1,031,084	1,008,025	1,030,780	548,339
2320	Transformer ARO	36,125	40,750	(17,795)	9,752	9,752	9,752
1855	Services (Overhead & Underground)	767,044	810,803	826,083	818,041	834,886	239,816
1860	Meters	437,220	50,588	86,526	36,768	37,122	14,937
1860	Meters (Smart Meters)	-	-	-	576,026	575,985	537,239
1905	Land	-	-	-	-		-
1908	Buildings & Fixtures	-	-	-	-		-
1910	Leasehold Improvements		-	-	-		-
1915	Office Furniture & Equipment (10 years)	36,748	35,481	38,918	43,707	42,182	42,182
1915	Office Furniture & Equipment (5 years)	-	-	-	-		
1920	Computer Equipment - Hardware	82,798	61,322	61,075	95,718	117,338	182,002
1920	Computer Equip.-Hardware(Post Mar. 22/04)	-	-	-	-		-
1920	Computer Equip.-Hardware(Post Mar. 19/07)	-	-	-	-		-
1930	Transportation Equipment	319,448	379,198	422,263	451,286	517,947	229,233
1935	Stores Equipment	-	-	-	582		
1940	Tools, Shop & Garage Equipment	70,171	67,190	64,281	63,212	69,194	69,194
1945	Measurement & Testing Equipment	22,199	21,965	23,528	23,178	25,371	25,371
1950	Power Operated Equipment	2,429	16,008	19,176	18,964	20,758	20,758
1955	Communications Equipment	796	1,549	7,294	15,012	19,622	9,446
1955	Communication Equipment (Smart Meters)	-	-	-	-		
1960	Miscellaneous Equipment	-	-	-	-		-
1975	Load Management Controls Utility Premises	-	-	-	-		-
1980	System Supervisor Equipment	34,343	34,343	34,343	34,343	34,343	34,343
1985	Miscellaneous Fixed Assets	-	-	-	-		
2440	Deferred Revenue						(12,712)
1995	Contributions & Grants	(367,800)	(509,632)	(628,096)	(668,555)	(729,900)	(456,959)
1996	Hydro One Current & Voltage Transformer	-	35,240	50,893	50,893	50,893	42,411
WIP	Work in Progress	-	-	-	-		-
Sub-Total Amortization Expense		**5,184,748**	**5,218,727**	**5,357,008**	**6,089,741**	**6,361,975**	**3,666,366**
Less: Amortization allocation to other trial balance accounts & overheads		**474,811**	**535,492**	**583,422**	**623,145**	**717,050**	**431,835**
Add: Smart Meter LTD adjustment to be included in depreciation					**1,393,943**		
					-		
:ess: Hydro One Current & Voltage Transformer posted to separate account			**35,240**	**50,893**	**50,893**	**50,583**	**42,411**
Add:Gov't Assistance Directly Credited to Income (4245)					**-**		**12,712**
NET AMORTIZATION EXPENSE TO INCOME STATEMENT		**4,709,938**	**4,647,995**	**4,722,693**	**6,809,646**	**5,594,342**	**3,204,832**

The year-over-year fluctuations in amortization expense (as seen above) are natural based on capital additions, disposal of assets, and assets becoming fully depreciated. The $2,086,953 increase for 2012 over 2011 is mainly due to the inclusion of Smart Meters in Thunder Bay Hydro's rate base. During 2012 the depreciation associated with Smart Meters increased by $576,026 plus the inclusion of life-to-date Smart Meter depreciation of $1,393,943. The decrease in amortization between 2013 and 2012 is due to the modification of 2013 capital asset and depreciation policies.

Amortization Variance Review

Thunder Bay Hydro has provided detailed amortization expense calculations using the OEB's methodology in Tables 4-2.25 through 4-2.29. See Exhibit 2, Table 2-2.6 for reconciliation to Thunder Bay Hydro's Audited Financial Statement amortization amounts (where applicable).

It should be noted that accumulated depreciation was not previously required to be segregated by asset category. As a result, the allocation of this balance by specific Distribution asset class was done in a reasonable manner based on the historical records that could be found. Further, disposals were not required to be segregated by asset category. Again this allocation was done in a reasonable manner based on historical records that could be found.

Overall the net depreciation calculation difference was below the materiality threshold. Variances are also a result of Thunder Bay Hydro's practice of amortization assets when put into use vs. the use of the half year rule as is done in the OEB tables.

Table 4-2.25 - Amortization Expense for 2011

Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013 (Note Thunder Bay Hydro adopting IFRS effective January 1, 2014)

Year **2011** **CGAAP**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (I)	Variance [2] (m) = (h) - (I)
1611	Computer Software (Formally known as Account 1925)	$ 779,512	$ 683,530	$ 95,982	$ 40,316	$ 116,141	5	$ 0	$ 23,228	$ 20,824	$ 2,404
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1805	Land	$ 133,038		$ 133,038	$ -	$ 133,038			$ -	$ -	$ -
1808	Buildings	$ 3,932,848	$ 121,308	$ 3,811,540	$ -	$ 3,811,540	50	$ 0	$ 76,231	$ 72,044	$ 4,187
1810	Leasehold Improvements	$ 33	$ -	$ 33	$ 2,473	$ 1,270	10	$ 0	$ 127	$ 423	$ (296)
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 8,124,042	$ 2,435,798	$ 5,688,244	$ -	$ 5,688,244	30	$ 0	$ 189,608	$ 169,361	$ 20,247
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 26,463,586	$ 2,664,720	$ 23,798,866	$ 2,682,500	$ 25,140,116	25	$ 0	$ 1,005,605	$ 995,308	$ 10,297
1835	Overhead Conductors & Devices	$ 27,698,210	$ -	$ 27,698,210	$ 2,137,304	$ 28,766,862	25	$ 0	$ 1,150,674	$ 1,203,746	$ (53,072)
1840	Underground Conduit	$ 12,688,093	$ 1,613,271	$ 11,074,822	$ 926,862	$ 11,538,253	26.05	$ 0	$ 442,927	$ 410,768	$ 32,159
1845	Underground Conductors & Devices	$ 16,994,271	$ 5,296,740	$ 11,697,531	$ 925,864	$ 12,160,463	26.05	$ 0	$ 466,812	$ 464,959	$ 1,853
1850	Line Transformers	$ 25,866,833	$ 3,466,624	$ 22,400,209	$ 1,063,799	$ 22,932,108	25	$ 0	$ 917,284	$ 1,031,084	$ (113,800)
2320	ARO	$ 161,743	$ -	$ 161,743	$ -	$ 161,743	16.5	$ 0	$ 9,803	$ (17,795)	$ 27,597
1855	Services (Overhead & Underground)	$ 19,519,438	$ -	$ 19,519,438	$ 705,597	$ 19,872,237	25	$ 0	$ 794,889	$ 826,083	$ (31,194)
1860	Meters	$ 1,077,396	$ 154,189	$ 923,207	$ 100,420	$ 973,417	26.04	$ 0	$ 37,382	$ 86,526	$ (49,144)
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1905	Land	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,344,490	$ 930,634	$ 413,856	$ 84,764	$ 456,239	10	$ 0	$ 45,624	$ 38,918	$ 6,706
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -	5	$ 0	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 2,698,325	$ 2,444,714	$ 253,611	$ 97,600	$ 302,411	5	$ 0	$ 60,482	$ 61,075	$ (593)
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1930	Transportation Equipment - 5 year	$ 1,182,680	$ 822,221	$ 360,459	$ 127,726	$ 424,322	5	$ 0	$ 84,864	$ 79,223	$ 5,641
	Transportation Equipment -8 year	$ 5,036,749	$ 2,383,997	$ 2,652,752	$ 271,840	$ 2,788,672	8	$ 0	$ 348,584	$ 343,040	$ 5,544
1935	Stores Equipment	$ 63,417	$ 63,417	$ (0)	$ -	$ (0)	10	$ 0	$ (0)	$ -	$ (0)
1940	Tools, Shop & Garage Equipment	$ 2,441,738	$ 1,884,715	$ 557,023	$ 29,425	$ 571,735	10	$ 0	$ 57,174	$ 64,281	$ (7,107)
1945	Measurement & Testing Equipment	$ 256,825	$ 6,291	$ 250,534	$ 13,637	$ 257,352	10	$ 0	$ 25,735	$ 23,528	$ 2,207
1950	Power Operated Equipment	$ 194,622	$ -	$ 194,622	$ -	$ 194,622	10	$ 0	$ 19,462	$ 19,176	$ 286
1955	Communications Equipment	$ 186,533	$ 161,754	$ 24,779	$ 48,777	$ 49,167	5	$ 0	$ 9,833	$ 7,294	$ 2,540
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ 515,152	$ -	$ 515,152	$ -	$ 515,152	15	$ 0	$ 34,343	$ 34,343	$ 0
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1995	Contributions & Grants	$ (12,744,352)	$ -	$ (12,744,352)	$ (2,958,053)	$ (14,223,378)	25	$ 0	$ (568,935)	$ (628,096)	$ 59,161
1996	Hydro One Current	$ 1,272,321	$ -	$ 1,272,321	$ -	$ 1,272,321	25	$ 0	$ 50,893	$ 50,893	$ (0)
WIP	Work in Progress	$ 1,758,058	$ -	$ 1,758,058	$ 1,192,201	$ 2,354,159			$ -	$ -	$ -
				$ -	$ -	$ -			$ -	$ -	$ -
	Total	$ 147,645,600	$ 25,133,922	$ 122,511,677	$ 7,493,052	$ 126,258,203			$ 5,282,631	$ 5,357,008	$ (74,377)

Table 4-2.26 - Amortization Expense for 2012 Bridge Year (CGAAP)

Appendix 2-CF
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013 (Note Thunder Bay Hydro adopting IFRS effective January 1, 2014)

Year 2012 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 1,136,032	$ 683,530	$ 452,502	$ 43,501	$ 474,252	$ 5	$ 0	$ 94,850	$ 93,245	$ 1,605
1612	Land Rights (Formally known as Account 1906)			$ -	$ -	$ -		$ -	$ -	$ -	$ -
1805	Land	$ 133,038		$ 133,038		$ 133,038		$ -	$ -	$ -	$ -
1808	Buildings	$ 3,932,848	$ 121,308	$ 3,811,540	$ -	$ 3,811,540	$ 50	$ 0	$ 76,231	$ 72,044	$ 4,187
1810	Leasehold Improvements	$ 2,507	$ -	$ 2,507	$ 73,000	$ 39,007	$ 10	$ 0	$ 3,901	$ 4,004	$ (103)
1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 8,124,042	$ 2,435,798	$ 5,688,244	$ -	$ 5,688,244	$ 30	$ 0	$ 189,608	$ 169,361	$ 20,247
1825	Storage Battery Equipment		$ -	$ -		$ -		$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 29,146,086	$ 3,813,071	$ 25,333,015	$ 4,076,237	$ 27,371,133	$ 25	$ 0	$ 1,094,845	$ 1,050,123	$ 44,722
1835	Overhead Conductors & Devices	$ 29,835,514	$ 450,523	$ 29,384,991	$ 3,582,045	$ 31,176,013	$ 25	$ 0	$ 1,247,041	$ 1,236,676	$ 10,365
1840	Underground Conduit	$ 13,614,955	$ 2,162,333	$ 11,452,622	$ 288,025	$ 11,596,634	$ 26	$ 0	$ 446,024	$ 406,911	$ 39,113
1845	Underground Conductors & Devices	$ 17,920,134	$ 5,821,959	$ 12,098,175	$ 1,263,182	$ 12,729,766	$ 26	$ 0	$ 489,606	$ 480,425	$ 9,181
1850	Line Transformers	$ 26,930,632	$ 4,492,949	$ 22,437,683	$ 1,409,100	$ 23,142,233	$ 25	$ 0	$ 925,689	$ 1,008,025	$ (82,336)
2320	ARO	$ 161,743	$ -	$ 161,743	$ -	$ 161,743	$ 17	$ 0	$ 9,803	$ 9,752	$ 51
1855	Services (Overhead & Underground)	$ 20,225,035	$ -	$ 20,225,035	$ 644,877	$ 20,547,474	$ 25	$ 0	$ 821,899	$ 818,041	$ 3,858
1860	Meters	$ 1,177,816	$ 273,770	$ 904,046	$ 61,903	$ 934,997	$ 26	$ 0	$ 35,961	$ 93,667	$ (57,705)
1860	Meters (Smart Meters) ***	$ 7,786,915		$ 7,786,915	$ 185,709	$ 7,879,770	$ 15	$ 0	$ 525,318	$ 519,127	$ 6,191
1905	Land			$ -	$ -	$ -		$ -	$ -	$ -	$ -
1908	Buildings & Fixtures			$ -	$ -	$ -		$ -	$ -	$ -	$ -
1910	Leasehold Improvements			$ -	$ -	$ -		$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,429,255	$ 1,019,519	$ 409,736	$ 71,352	$ 445,412	$ 10	$ 0	$ 44,541	$ 43,707	$ 834
1915	Office Furniture & Equipment (5 years)			$ -	$ -	$ -	$ 5	$ 0	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 2,733,154	$ 2,351,291	$ 381,863	$ 222,408	$ 493,067	$ 5	$ 0	$ 98,613	$ 95,718	$ 2,895
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ -	$ -		$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -	$ -	$ -		$ -	$ -	$ -	$ -
1930	Transportation Equipment - 5 year	$ 1,310,406	$ 936,677	$ 373,729	$ 280,114	$ 513,786	$ 5	$ 0	$ 102,757	$ 102,774	$ (17)
	Transportation Equipment - 8 yr	$ 5,226,589	$ 2,427,764	$ 2,798,825	$ 184,609	$ 2,891,130	$ 8	$ 0	$ 361,391	$ 348,512	$ 12,879
1935	Stores Equipment	$ 63,417	$ 63,417	$ (0)	$ -	$ (0)	$ 10	$ 0	$ (0)	$ 582	$ (582)
1940	Tools, Shop & Garage Equipment	$ 2,464,872	$ 1,868,816	$ 596,056	$ 51,585	$ 621,848	$ 10	$ 0	$ 62,185	$ 63,212	$ (1,027)
1945	Measurement & Testing Equipment	$ 270,461	$ 66,143	$ 204,318	$ 23,873	$ 216,255	$ 10	$ 0	$ 21,625	$ 23,178	$ (1,552)
1950	Power Operated Equipment	$ 194,622	$ -	$ 194,622	$ -	$ 194,622	$ 10	$ 0	$ 19,462	$ 18,964	$ 499
1955	Communications Equipment	$ 212,477	$ 138,921	$ 73,556	$ 28,012	$ 87,562	$ 5	$ 0	$ 17,512	$ 15,012	$ 2,500
1955	Communication Equipment (Smart Meters)			$ -	$ -	$ -		$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment			$ -	$ -	$ -	$ 10	$ 0	$ -	$ -	$ -
1975	Load Management Controls Utility Premises			$ -	$ -	$ -		$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 515,152	$ -	$ 515,152	$ 51,474	$ 540,889	$ 15	$ 0	$ 36,059	$ 34,343	$ 1,716
1985	Miscellaneous Fixed Assets			$ -	$ -	$ -		$ -	$ -	$ -	$ -
1995	Contributions & Grants	$ (15,702,405)	$ -	$ (15,702,405)	$ (2,022,925)	$ (16,713,867)	$ 25	$ 0	$ (668,555)	$ (668,555)	$ 0
1996	Hydro One Current	$ 1,272,321	$ -	$ 1,272,321	$ -	$ 1,272,321	$ 25	$ 0	$ 50,893	$ 50,893	$ (0)
WIP	Work in Progress	$ 2,950,259	$ -	$ 2,950,259	$ (1,681,465)	$ 2,109,527	$ -		$ -	$ -	$ -
				$ -	$ -	$ -			$ -	$ -	$ -
	Total	$ 163,067,875	$ 29,127,789	$ 133,940,086	$ 8,836,615	$ 138,358,393			$ 6,107,262	$ 6,089,741	$ 17,521

1 **Table 4-2.27 – Amortization Expense 2013 Test CGAAP**

Appendix 2-CF

Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013 (Note Thunder Bay Hydro adopting IFRS effective January 1, 2014)

Year 2013 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (I)	Variance [2] (m) = (h) - (I)
1611	Computer Software (Formally known as Account 1925)	$ 1,179,533	$ 762,801	$ 416,732	$ 77,200	$ 455,332	5	20%	$ 91,066	$ 97,865	$ (6,799)
1612	Land Rights (Formally known as Account 1906)			$ -		$ -		0%	$ -	$ -	$ -
1805	Land	$ 133,038		$ 133,038	$ -	$ 133,038		0%	$ -	$ -	$ -
1808	Buildings	$ 3,932,848	$ 121,308	$ 3,811,540	$ 3,303,500	$ 5,463,290	50	2%	$ 109,266	$ 97,294	$ 11,972
1808	Garage	$ -	$ -		$ -	$ -	50	2%	$ -	$ -	$ -
1810	Leasehold Improvements	$ 75,507	$ -	$ 75,507	$ -	$ 75,507	10	10%	$ 7,551	$ 8,399	$ (848)
1820	Distribution Equipment - ARO		$ -	$ -	$ -	$ -	30	3%	$ -	$ -	$ -
1820	Distribution Station Equipment Normally Primary below 50kv	$ 8,124,042	$ 2,435,798	$ 5,688,244	$ -	$ 5,688,244	30	3%	$ 189,608	$ 169,361	$ 20,247
1825	Storage Battery Equipment		$ -	$ -		$ -		0%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 33,222,320	$ 4,826,692	$ 28,395,628	$ 3,355,911	$ 30,073,584	25	4%	$ 1,202,943	$ 1,115,044	$ 87,899
1835	Overhead Conductors & Devices	$ 33,417,559	$ 889,688	$ 32,527,871	$ 3,395,046	$ 34,225,394	25	4%	$ 1,369,016	$ 1,302,012	$ 67,003
1840	Underground Conduit	$ 13,902,980	$ 2,862,333	$ 11,040,647	$ 246,571	$ 11,163,932	25.94	4%	$ 430,375	$ 411,032	$ 19,343
1845	Underground Conductors & Devices	$ 19,183,316	$ 6,723,119	$ 12,460,197	$ 604,296	$ 12,762,345	25.94	4%	$ 491,995	$ 504,694	$ (12,699)
1850	Line Transformers	$ 28,339,732	$ 5,740,734	$ 22,598,998	$ 1,240,223	$ 23,219,109	25	4%	$ 928,764	$ 1,030,780	$ (102,015)
2320	ARO	$ 161,743	$ -	$ 161,743	$ -	$ 161,743	17	6%	$ 9,803	$ 9,752	$ 51
1855	Services (Overhead & Underground)	$ 20,869,912		$ 20,869,912	$ 924,514	$ 21,332,169	25	4%	$ 853,287	$ 834,886	$ 18,401
1860	Meters	$ 1,192,673	$ 424,033	$ 768,640	$ 10,989	$ 774,134	25.26	4%	$ 30,647	$ 37,122	$ (6,476)
1860	Meters (Smart Meters) ***	$ 8,019,670		$ 8,019,670	$ 172,162	$ 8,105,751	15	7%	$ 540,383	$ 575,985	$ (35,601)
1905	Land			$ -		$ -		0%	$ -	$ -	$ -
1908	Buildings & Fixtures			$ -		$ -		0%	$ -	$ -	$ -
1910	Leasehold Improvements			$ -		$ -		0%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 1,420,039	$ 1,073,892	$ 346,147	$ 36,050	$ 364,172	10	10%	$ 36,417	$ 42,182	$ (5,765)
1915	Office Furniture & Equipment (5 years)			$ -		$ -	5	20%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 2,955,562	$ 2,354,291	$ 601,271	$ 81,600	$ 642,071	5	20%	$ 128,414	$ 117,338	$ 11,076
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -		0%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -		0%	$ -	$ -	$ -
1930	Transportation Equipment 5yr	$ 1,423,109	$ 772,444	$ 650,665	$ 135,000	$ 718,165	5	20%	$ 143,633	$ 130,434	$ 13,199
1930	Transportation Equipment 8yr	$ 5,120,740	$ 2,361,310	$ 2,759,430	$ 825,345	$ 3,172,102	8	13%	$ 396,513	$ 387,513	$ 9,000
1935	Stores Equipment	$ 63,417	$ 63,417	$ (0)	$ -	$ (0)	10	10%	$ (0)	$ -	$ (0)
1940	Tools, Shop & Garage Equipment	$ 2,516,457	$ 1,528,795	$ 987,662	$ 73,700	$ 1,024,512	10	10%	$ 102,451	$ 115,323	$ (12,872)
1945	Measurement & Testing Equipment	$ 294,334	$ 298,143	$ (3,809)	$ 22,940	$ 7,661	10	10%	$ 766	$ -	$ 766
1950	Power Operated Equipment	$ 194,622	$ 199,142	$ (4,520)	$ 13,400	$ 2,180	10	10%	$ 218	$ -	$ 218
1955	Communications Equipment	$ 240,489	$ 162,129	$ 78,360	$ 104,756	$ 130,738	5	20%	$ 26,148	$ 19,622	$ 6,526
1955	Communication Equipment (Smart Meters)			$ -		$ -		0%	$ -	$ -	$ -
1960	Miscellaneous Equipment			$ -		$ -	10	10%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		$ -	$ -		$ -		0%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 566,626		$ 566,626	$ 2,077	$ 567,664	15	7%	$ 37,844	$ 34,343	$ 3,501
1985	Miscellaneous Fixed Assets			$ -		$ -		0%	$ -	$ -	$ -
2440	Deferred Revenue				$ -	$ -	25	4%	$ -	$ -	$ -
1995	Contributions & Grants	$ (17,725,330)	$ -	$ (17,725,330)	$ (1,044,834)	$ (18,247,747)	25	4%	$ (729,910)	$ (729,900)	$ (10)
1996	Hydro One Current	$ 1,272,321	$ -	$ 1,272,321	$ -	$ 1,272,321	25	4%	$ 50,893	$ 50,893	$ (0)
WIP	Work in Progress	$ 1,268,794		$ 1,268,794	$ (190,812)	$ 1,173,388	0		$ -	$ -	$ -
				$ -	$ -	$ -			$ -		$ -
	Total	$ 171,366,050	$ 33,600,070	$ 137,765,980	$ 13,389,634	$ 144,460,797			$ 6,448,091	$ 6,361,975	$ 86,116

Table 4-2.28 – Amortization Expense 2013 Test MCGAAP

Appendix 2-CG

Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2013 (Note Thunder Bay Hydro adopting IFRS effective January 1, 2014)

Year 2013 MCGAAP

Account	Description	Opening NBV as at Jan 1, 2013 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 192,933	$ 77,200	5	3	33.33%	$ 38,587	$ 12,867	$ 51,453	$ 51,926	$ (472)
1612	Land Rights (Formally known as Account 1906)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1805	Land	$ 133,038	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1808	Buildings	$ 2,070,381	$ 3,500	29	50	2.00%	$ 71,392	$ 35	$ 71,427	$ 72,044	$ (617)
1808	Garage	$ -	$ 3,300,000	0	72	1.39%	$ -	$ 22,917	$ 22,917	$ 25,250	$ (2,333)
1810	Leasehold Improvements	$ 71,057	$ -	9	15	6.67%	$ 8,360	$ -	$ 8,360	$ 8,399	$ (39)
1815	Distribution Equipment - ARO	$ -	$ 45,125		3	33.33%	$ -	$ 7,521	$ 7,521	$ 7,386	$ 134
1820	Distribution Station Equipment normally Primary below 50 kV	$ 2,248,172	$ 1,879	7	50	2.00%	$ 321,167	$ 19	$ 321,186	$ 319,827	$ 1,359
1825	Storage Battery Equipment	$ -	$ -	0	40	2.50%	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 21,743,863	$ -	32	0	0.00%	$ 679,496	$ -	$ 679,496	$ 688,942	$ (9,446)
	Poles, Towers & Fixtures - New Additions Rate		$ 3,062,513	0	40	2.50%	$ -	$ 38,281	$ 38,281	$ 36,516	$ 1,765
	Steel Cross Arms	$ 95,863		62	0	0.00%	$ 1,557	$ -	$ 1,557	$ 1,533	$ 24
	Steel Cross Arms - New Additions Rate		$ 6,105		70	1.43%	$ -	$ 44	$ 44	$ 44	$ (0)
	Fibre Glass Cross Arms	$ 9,536	$ -	74		0.00%	$ 129	$ -	$ 129	$ 130	$ (1)
	Fibre Glass Cross Arms - New Addition Rate		$ 1,274		80	1.25%	$ -	$ 8	$ 8	$ 8	$ 0
1835	O/H Conductors & Devices - Switches	$ 1,052,092	$ -	17	0	0.00%	$ 61,382	$ -	$ 61,382	$ 55,776	$ 5,607
	O/H Conductors & Devices - Switches - New Addition Rate		$ 125,032		40	2.50%	$ -	$ 1,563	$ 1,563	$ 1,550	$ 13
	O/H Conductors & Devices - Primary & Neutral Cables	$ 13,604,114	$ -	44	0	0.00%	$ 309,184	$ -	$ 309,184	$ 308,197	$ 987
	O/H Conductors & Devices - Primary & Neutral Cables - New Addition Rate		$ 2,018,226		60	1.67%	$ -	$ 16,819	$ 16,819	$ 16,819	$ -
	O/H Conductors & Devices - Secondary Cables	$ 2,210,169	$ -	37	0	0.00%	$ 59,734	$ -	$ 59,734	$ 46,209	$ 13,526
	O/H Conductors & Devices - Secondary Cables - New Addition Rate		$ 569,243		60	1.67%	$ -	$ 4,744	$ 4,744	$ 4,744	$ 0
	O/H Conductors & Devices - Reclosures	$ 643,195	$ -	26	0	0.00%	$ 24,363	$ -	$ 24,363	$ 20,778	$ 3,585
	O/H Conductors & Devices - Reclosures - New Addition Rate		$ 144,678		40	2.50%	$ -	$ 1,808	$ 1,808	$ 1,808	$ (0)
1840	U/G Conduit - Trenches	$ 138,312	$ -	11	0	0.00%	$ 12,506	$ -	$ 12,506	$ 14,463	$ (1,957)
	U/G Conduit - Conduits	$ 4,807,157	$ -	64	0	0.00%	$ 75,112	$ -	$ 75,112	$ 72,295	$ 2,817
	U/G Conduit - Conduits - New Addition Rate		$ 163,913		80	1.25%	$ -	$ 1,024	$ 1,024	$ 1,024	$ (0)
	U/G Conduit - Foundations	$ 924,864	$ -	46	0	0.00%	$ 19,945	$ -	$ 19,945	$ 19,780	$ 165
	U/G Conduit - Foundations - New Addition Rates		$ 42,221		55	1.82%	$ -	$ 384	$ 384	$ 384	$ (0)
1845	U/G Conductors & Devices - Primary Cables in Duct	$ 8,021,229	$ -	32	0	0.00%	$ 250,663	$ -	$ 250,663	$ 243,220	$ 7,444
	U/G Conductors & Devices - Primary Cables in Duct - New Addition Rates		$ 465,825		40	2.50%	$ -	$ 5,823	$ 5,823	$ 5,823	$ 0
	U/G Conductors & Devices - Primary Cables Direct Buried	$ 516,660	$ -	8	0	0.00%	$ 64,583	$ -	$ 64,583	$ 58,711	$ 5,871
	U/G Conductors & Devices - Secondary Cables in Duct	$ 567,939	$ -	25	0	0.00%	$ 23,153	$ -	$ 23,153	$ 19,441	$ 3,712
	U/G Conductors & Devices - Secondary Cables Direct Buried	$ 93,826	$ -	11	0	0.00%	$ 8,744	$ -	$ 8,744	$ 7,215	$ 1,529
	U/G Conductors & Devices - UG Switchgear	$ 496,075	$ -	22	0	0.00%	$ 22,376	$ -	$ 22,376	$ 19,939	$ 2,437
	U/G Conductors & Devices - UG Switchgear - New Addition Rate		$ 50,000		30	3.33%	$ -	$ 833	$ 833	$ 833	$ 0
1850	Line Transformers - Vault	$ 63,516	$ -	10	0	0.00%	$ 6,541	$ -	$ 6,541	$ 11,082	$ (4,540)
	Line Transformers - Enclosure	$ 58,611	$ -	10	0	0.00%	$ 5,867	$ -	$ 5,867	$ 5,522	$ 345
	Line Transformers - Pole Top	$ 7,726,676	$ -	24	0	0.00%	$ 321,945	$ -	$ 321,945	$ 317,973	$ 3,971
	Line Transformers - Pole Top - New Addition Rate		$ 1,132,505		40	2.50%	$ -	$ 14,156	$ 14,156	$ 14,156	$ 0
	Line Transformers - Pad Mount Transformer Single Phase	$ 2,322,316	$ -	20	0	0.00%	$ 113,728	$ -	$ 113,728	$ 105,096	$ 8,632
	Line Transformers - Pad Mount Transformer 3 Phase	$ 2,222,364	$ -	22	0	0.00%	$ 101,017	$ -	$ 101,017	$ 94,510	$ 6,507
2320	ARO	$ 82,077	$ -	12	0	0.00%	$ 7,137	$ -	$ 7,137	$ 9,752	$ (2,615)
1855	Services (O/H & U/G) - O/H Conductors	$ 3,869,114	$ -	37	0	0.00%	$ 103,480	$ -	$ 103,480	$ 96,447	$ 7,033
	Services (O/H & U/G) - O/H Conductors - New Addition Rate		$ 508,923		60	1.67%	$ -	$ 4,241	$ 4,241	$ 4,241	$ (0)
	Services (O/H & U/G) - U/G in Duct	$ 2,406,432		21	0	0.00%	$ 113,995	$ -	$ 113,995	$ 101,192	$ 12,803
			$ 253,088		40	2.50%	$ -	$ 3,164	$ 3,164	$ 3,164	$ -
	Services (O/H & U/G) -U/G Direct Buried	$ 278,022	$ -	11	40	2.50%	$ 25,911	$ -	$ 25,911	$ 34,772	$ (8,861)
1860	Meters - Industrial/Commercial Energy Meters	$ 29,498	$ -	27	35	2.86%	$ 1,073	$ -	$ 1,073	$ 2,254	$ (1,181)
	Meters - CT & PT	$ 107,129	$ -	26	50	2.00%	$ 4,122	$ -	$ 4,122	$ 4,314	$ (192)
	Meters - Primary	$ 217,804		26	0	0.00%	$ 8,371	$ -	$ 8,371	$ 8,119	$ 252
	Meters - Primary - New Addition Rate		$ 25,000		50	2.00%	$ -	$ 250	$ 250	$ 250	$ -
		$ -	$ -		0	0.00%	$ -	$ -	$ -	$ -	$ -
			$ -			0.00%	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters) - Phase 1	$ 4,484,153	$ 118,374	12	15	6.67%	$ 386,565	$ 3,946	$ 390,511	$ 391,533	$ (1,023)
	Meters (Smart Meters) - Phase 2	$ 424,136	$ -	12	15	6.67%	$ 36,881	$ -	$ 36,881	$ 37,319	$ (438)
	Meters (Smart Meters) - Phase 3	$ 977,657	$ -	12	15	6.67%	$ 80,731	$ -	$ 80,731	$ 81,630	$ (899)
	Meters (Smart Meters) - Repeaters Data Coll	$ 312,071	$ -	12	15	6.67%	$ 26,115	$ -	$ 26,115	$ 26,756	$ (641)
1905	Land	$ -	$ -		0	0.00%	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -	$ -		0	0.00%	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements	$ -	$ -		0	0.00%	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 249,892	$ 36,050	6	10	10.00%	$ 40,966	$ 1,803	$ 42,768	$ 42,182	$ 586
1915	Office Furniture & Equipment (5 years)	$ -	$ -		5	20.00%	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 312,212	$ 81,600	2	3	33.33%	$ 168,763	$ 13,600	$ 182,363	$ 182,002	$ 361
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment - Trailers			0	20	5.00%	$ -	$ -	$ -		$ -
	Transportation Equipment - Buckets and Heavy Equipment	$ 1,636,989	$ 825,345	10	15	6.67%	$ 165,352	$ 27,512	$ 192,864	$ 191,875	$ 989
	Transportation Equipment - Light Vehicles	$ 381,828	$ 135,000	12	12	8.33%	$ 31,819	$ 5,625	$ 37,444	$ 37,358	$ 86
1935	Stores Equipment	$ (0)	$ -		10	10.00%	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 246,897	$ 73,700	4	10	10.00%	$ 65,839	$ 3,685	$ 69,524	$ 69,194	$ 330
1945	Measurement & Testing Equipment	$ 136,924	$ 22,940	6	10	10.00%	$ 24,451	$ 1,147	$ 25,598	$ 25,371	$ 227
1950	Power Operated Equipment	$ 135,137	$ 13,400	7	10	10.00%	$ 20,170	$ 670	$ 20,840	$ 20,758	$ 82
1955	Communications Equipment	$ 78,033	$ 104,756	0	5	20.00%	$ -	$ 10,476	$ 10,476	$ 9,446	$ 1,030
1955	Communication Equipment (Smart Meters)	$ -	$ -		5	20.00%	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -		10	10.00%	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -			0.00%	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 187,730	$ -	6	50	2.00%	$ 30,426	$ -	$ 30,426	$ 34,343	$ (3,917)
1985	Miscellaneous Fixed Assets	$ -	$ -		40	2.50%	$ -	$ -	$ -	$ -	$ -
2440	Deferred Revenue	$ -	$ (989,985)		40	2.50%	$ -	$ (12,375)	$ (12,375)	$ (12,712)	$ 337
1995	Contributions & Grants	$ (13,989,347)	$ -	31	25	4.00%	$ (457,168)	$ -	$ (457,168)	$ (456,959)	$ (210)
1996	Hydro One Current	$ 1,135,295	$ -	27	25	4.00%	$ 42,841	$ -	$ 42,841	$ 42,411	$ 430
WIP	Work in Progress	$ 1,268,794	$ (285,238)	0	0	0.00%	$ -	$ -	$ -	$ -	$ -
		$ -				0.00%	$ -	$ -	$ -	$ -	$ -
	Total	$ 77,002,434	$ 12,132,192				$ 3,529,372	$ 192,587	$ 3,721,959	$ 3,666,366	$ 55,593

ASSET RETIREMENT OBLIGATIONS

Included in capital assets are Asset Retirement Obligations ("ARO") related to PCB's subject to removal from transformers, and sub-station decommissioning costs. The costs and associated amortization have been shown separately in the Fixed Asset Continuity Schedules and Depreciation schedules.

The ARO associated with transformers was calculated based on an estimate of PCB destruction costs and associated transportation costs based on our legislated requirement to remove PCB's greater than 50 ppm currently in our system. The ARO is being amortized over the applicable removal period.

The ARO associated with sub-station decommissioning costs was calculated based on the estimated third party costs associated with each station scheduled for decommissioning. Such costs were apportioned between opening retained earnings and capital assets based upon the remaining service life of applicable stations. The ARO is being amortized based on the applicable station's estimated decommissioning date.

The net book value, depreciation and accretion costs associated with ARO's have been removed from Rate Base calculations.

INCOME TAX

TAX CALCULATIONS

Table 4-3.1 below provides a summary of the 2009, 2010, 2011 Actual, included in audited statements, and the 2012 Bridge Year (CGAAP) and 2013 Test Year (CGAAP) income tax estimate using rates as currently prescribed by Canada Revenue Agency. The 2009-2011 actuals have been adjusted for “non-wires” activities such as Sentinel Light rental income/expenses and other non-wires expenses not included in the 2012 Bridge Year and 2013 Test Year for consistency in presentation. A copy of Thunder Bay Hydro’s annual federal and provincial tax return has been provided as Appendix 4-D to this exhibit. In accordance with the June 2012 filing requirements the Board's PILs model has also been completed and submitted and is consistent with the PILs included in the 2013 revenue requirement.

Table 4-3.1 - Income Tax

Description	2009 Actuals Adjusted for "Non-Wires" Activity	2010 Actuals Adjusted for "Non-Wires" Activity	2011 Actuals Adjusted for "Non-Wires" Activities	2012 Bridge	2013 CGAAP Test
Income Taxes - Current per Actual Returns	748,574	580,821	706,508		
Adjustment for" Non-Wires" Activity	10,427	44,522	28,552		
Income Taxes - Current	759,001	625,343	735,060	315,925	25,418
Less: Prior Period Adjustments	-	-	-	-	-

Thunder Bay Hydro’s detailed tax calculations using the most recent tax rates are provided in Table 4-3.2.

Table 4-3.2 - Detailed Tax Calculations for 2009 to 2013

Item	2009 Actuals Adjusted for "Non-Wires" Activity	2010 Actuals Adjusted for "Non-Wires" Activity	2011 Actuals Adjusted for "Non-Wires" Activity	2012 Bridge	2013 CGAAP Test
Accounting Net Income Before Taxes	1,358,018	735,032	2,692,266	1,522,399	1,093,030
Adjustment for "non-wires" activity	32,283	144,739	106,181		
Adjusted Accounting Net Income Before Taxes	1,390,301	879,771	2,798,447	1,522,399	1,093,030
Additions					
Amortization of assets	4,965,686	4,963,044	5,032,895	5,749,279	5,948,742
		-	-		
	-	-			
Taxable Capital Gains	-	-			30,000
	-	-			
Apprenticeship Training Tax Credit	86,566	102,630	105,863	125,000	90,625
Non deductible meals	20,713	20,843	17,993	13,193	9,605
Non-deductible future benefit retirement accruals	374,564	285,940	324,466	249,765	259,266
Smart Meter net revenues	831,276	1,195,464	1,067,020	211,313	
Regulatory Assets - recovered on Deferrals, not previously taxed	294,365	643,800	196,244		
Charitable Donations		16,434	16,786		
Political Donations		1,244			
Deductions					
Capital cost allowance from Schedule 8	4,760,293	5,320,324	5,810,032	5,877,535	6,507,304
Gain (Loss) on Disposal of Assets	14,640	400	25,451	(12,200)	56,170
Cumulative Eligible Capital Deduction	5,275	71,703	66,684	62,016	56,675
Capital Tax in Provision	5,705				
IFRS Implementation Expense deferred	5,640	2,662	42,993		
Future benefit premiuns paid	239,733	212,474	390,446	97,516	155,627
Capitalized portion of future benefit expenses	100,248	36,591	51,989	39,740	42,133
PILS Deferral Overpayment	186,079	-			
Regulatory Assets - deductible for tax purposes	57,403	50,900	12,773		
ARO Expense	-	47,495	32,077	14,627	14,627
Prior Period Adjustment	-	-	-	-	-
	-	-	-	-	-
Total Tax Adjustments to Accounting Income	1,198,154	1,486,850	328,822	269,315	(494,299)
Income for Tax Purposes	2,588,455	2,366,621	3,127,269	1,791,714	598,731
	-	-	-	-	-
Effective Tax Rate Reflecting Tax Credits (Federal & Provincial)	32.30%	30.76%	26.89%	24.61%	19.37%
	-	-	-	-	-
Income Taxes Before Credits	836,071	727,973	840,923	440,925	116,043
Less: Apprenticeship Training Credit	77,070	102,630	105,863	125,000	90,625
Less: Political Donations multiplied by tax rate		383	-		
Income Taxes	759,001	625,343	735,060	315,925	25,418
Capital Tax Calculation:					
Total Rate Base		-	-	-	-
	81,646,872	76,197,769	-	-	-
Rate	0.225%	0.150%	0.000%	0.000%	0.000%
Capital Tax - As Calculated	**183,705**	**56,679**	**-**	**-**	**-**
Capital Tax - As per Audited Statements	**178,000**	**60,000**	**3,752**	**-**	**-**

TAX CREDIT CALCULATIONS

Included in the 2012 Bridge Year and the 2013 Test Year are Apprenticeship Tax Credits. These credits have been calculated based on the current rules dictated by Canada Revenue Agency. The 2013 Test Year credits have been annualized based on the projected credits for 2013-2016. Table 4-3.3 and 4-3.4 below detail how the Apprenticeship Tax Credits have been calculated.

Table 4-3.3 - Apprenticeship Tax Credit Calcuation 2012

2012 Apprenticeships	Max Tax Credit
Apprentice #1	10,000.00
Apprentice #2	10,000.00
Apprentice #3	10,000.00
Apprentice #4	10,000.00
Apprentice #5	10,000.00
Apprentice #6	10,000.00
Apprentice #7	10,000.00
Apprentice #8	10,000.00
Apprentice #9	10,000.00
Apprentice #10	10,000.00
Apprentice #11	10,000.00
Apprentice #12	10,000.00
Apprentice #13 (Jan - June)	5,000.00
	125,000.00

Table 4-3.4 - Apprenticeship Tax Credit Calcuation 2013

2013 Apprenticeships		Max Tax Credit
Apprentice #1		10,000.00
Apprentice #2		10,000.00
Apprentice #3 (Jan - Apr)		3,333.33
Apprentice #4		10,000.00
Apprentice #5 (Jan - May)		4,166.67
Apprentice #6 (Jan - June)		5,000.00
Apprentice #7		10,000.00
Apprentice #8		10,000.00
Apprentice #9		10,000.00
Apprentice #10		10,000.00
Apprentice #11		10,000.00
Apprentice #12		10,000.00
Apprentice #13		10,000.00
Apprentice #14		10,000.00
Apprentice #15		10,000.00
		132,500.00
2014 Apprenticeships	9	90,000.00
2015 Apprenticeships	8	80,000.00
2016 Apprenticeships	6	60,000.00
Total		362,500.00
Annualized		90,625.00

CAPITAL COST ALLOWANCE

Thunder Bay Hydro is providing Capital Cost Allowance continuity schedules for the 2012 Bridge Year and the 2013 Test Year (Tables 4-3.5 - 4-3.8) are as follows:

Table 4-3.5 - 2012 CCA Contiunity Schedule

CCA Continuity Schedule CGAAP 2012

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	50,016,351	0	0	50,016,351	0	0	50,016,351	0	50,016,351	4%	2,000,654	48,015,697
2	Distribution System - pre 1988		0	0	0	0	0	0	0	0	6%	0	0
6	Buildings - after 1990		0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	786,152	0	0	786,152	174,822	0	960,974	87,411	873,563	20%	174,713	786,261
10	Computer Hardware/ Vehicles	1,419,348	0	0	1,419,348	464,723	14,400	1,869,671	225,162	1,644,510	30%	493,353	1,376,318
10.1	Certain Automobiles		0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	19,194	0	0	19,194	43,501	0	62,695	21,751	40,945	100%	40,945	21,751
3	Buildings - pre 1990		0	0	0	0	0	0	0	0	5%	0	0
4	Buildings	1,569,369	0	0	1,569,369	0	0	1,569,369	0	1,569,369	6%	94,162	1,475,207
13 3	Lease # 3	2,226	0	0	2,226	73,000	0	75,226	36,500	38,726	20%	7,745	67,481
13 4	Lease # 4		0	0	0	0	0	0	0	0		0	0
14	Franchise		0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs		0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment		0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	7,508	0	0	7,508	0	0	7,508	0	7,508	45%	3,379	4,129
50	Computers & Systems Hardware acq'd post Mar 19/07	89,461	0	0	89,461	222,408	0	311,869	111,204	200,665	55%	110,366	201,503
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)		0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	32,132,931			32,132,931	9,539,626	0	41,672,557	4,769,813	36,902,744	8%	2,952,220	38,720,337
	SUB-TOTAL - UCC	**86,042,540**	**0**	**0**	**86,042,540**	**10,518,080**	**14,400**	**96,546,220**	**5,251,840**	**91,294,380**		**5,877,535**	**90,668,684**

Table 4-3.6- 2012 Cumulative Eligible Captial Calculation

Cumulative Eligible Capital Calculation CGAAP				
Cumulative Eligible Capital				885,942
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December	0	x 1/2 =	0	
			0	885,942
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				885,942
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	885,942
Cumulative Eligible Capital Balance				885,942
CEC Deduction	7%			62,016
Cumulative Eligible Capital - Closing Balance				823,926

Table 4-3.7 – CCA Continuity Schedule CGAAP (2013)

CCA Continuity Schedule CGAAP (2013)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	48,015,697	0	0	48,015,697	0	0	48,015,697	0	48,015,697	4%	1,920,628	46,095,069
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
6	Buildings - after 1990	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	786,261	0	0	786,261	250,846	0	1,037,107	125,423	911,684	20%	182,337	854,771
10	Computer Hardware/ Vehicles	1,378,478	0	0	1,378,478	960,345	12,500	2,326,323	480,173	1,846,151	30%	553,845	1,772,478
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	21,751	0	0	21,751	77,200	0	98,951	38,600	60,351	100%	60,351	38,600
3	Buildings - pre 1990	0	0	0	0	0	0	0	0	0	5%	0	0
4	Buildings	1,475,207	0	0	1,475,207	3,303,500	0	4,778,707	1,651,750	3,126,957	6%	187,617	4,591,089
13 3	Lease # 3	67,481	0	0	67,481	0	0	67,481	0	67,481	20%	13,496	53,985
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	4,129	0	0	4,129	0	0	4,129	0	4,129	45%	1,858	2,271
50	Computers & Systems Hardware acq'd post Mar 19/07	201,503	0	0	201,503	81,600		283,103	40,800	242,303	55%	133,267	149,836
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	38,720,335			38,720,335	8,906,955	0	47,627,290	4,453,478	43,173,813	8%	3,453,905	44,173,385
	SUB-TOTAL - UCC	**90,670,842**	**0**	**0**	**90,670,842**	**13,580,446**	**12,500**	**104,238,788**	**6,790,223**	**97,448,565**		**6,507,304**	**97,731,484**

Table 4-3.8 - Cumulative Eligible Capital Calculation CGAPP (2013)

Cumulative Eligible Capital Calculation				
Cumulative Eligible Capital				823,926
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday December 31, 2002	0	x 1/2 =	0	
			0	823,926
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				823,926
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the year				
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	823,926
Cumulative Eligible Capital Balance				823,926
CEC Deduction	7.00%			57,675
Cumulative Eligible Capital - Closing Balance				766,251

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MCGAAP – IMPACT ON OM&A

Conversion to MCGAAP

Thunder Bay Hydro has amended the accounting policies used for 2013 to be more in line with Modified International Reporting Standards (MIFRS).

International Accounting Standard 16 (IAS 16) – Property, Plant and Equipment (PP&E), states the cost of an item of PP&E includes any costs that are 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 Canadian GAAP allowed for the capitalization of general and administrative overhead, MIFRS does not.

In order to allocate costs between operating expenses and capital expenses, Thunder Bay Hydro utilizes the following burdens departments:

- Downtime
- Engineering
- Fleet
- Purchasing & Stores
- Supervisory

In reviewing each of these burdens Thunder Bay Hydro has identified the following expenses that are not appropriate to capitalize under MIFRS.

Downtime

The payroll burden has included the full costs of all employees including, wages, benefits, safety training and education expenses. The safety, training and education expenses are indirect expenses and cannot be capitalized under MIFRS. These expenses include the following:

In-house training

- Miscellaneous Courses and Workshops
- Safety Consulting
- EUSA
- Safety Meetings and training

The reduction in Downtime burden eligible for capitalization was $450,586.
The total reduction in downtime burden for these expenses to capital projects is $297,382.

Engineering

The Engineering burden includes the engineering manager, a part time engineering clerk, technicians, and drafting and design services.

In reviewing the work activities of the engineering technicians it was found that most of their time was directly attributable to capital projects and therefore appropriately included in the Engineering burden. However, the engineering manager provided a supervisory role over the technicians and the engineering clerk provides a support role to the technicians which are not directly attributable to specific capital projects. Under MIFRS these expenses will no longer be capitalized but will be allocated to OM&A expenses.

In addition the Engineering burden also included miscellaneous charges such as IT expenses, property charges and other miscellaneous departmental expenses. These expenses are considered general expenses and not directly attributable to specific capital projects. Under MIFRS these expenses will no longer be capitalized.

The reduction in the Engineering costs eligible for capitalization is summarized below:

Supervisory & Admin Labour	$180,210
Miscellaneous Department Charges	$255,720
Total	$435,930

The reduction in engineering burden to capital projects was $232,559.

Fleet

Through the Fleet burden, the total cost of operating all vehicles is charged to specific jobs, based on an hourly rate for the time each vehicle is on a job. Timesheets are completed for each truck and therefore the costs are directly attributable to specific projects. However, included in the Fleet expense were the following expenses that are considered general or administrative under MIFRS and therefore are not eligible for capitalization.

Wages and benefits	$268,049
Miscellaneous Department Charges	$250,759
Total	$518,808

The reduction in fleet burden to capital projects was $502,513.

Purchasing & Stores

Included in this burden are the expenses of our Purchasing and Stores departments. Expenses included labour, vehicle charges, IT expense, property charges and other miscellaneous department expenses. The labour costs include the purchasing manager, buyers and stores keepers. Based on review of the expenses of the Purchasing and Stores departments it was determined that the Purchasing function was a general corporate function and therefore not eligible for capitalization. Further the purchasing manager's time was partially for supervisory activities of the stores keepers and therefore not eligible for capitalization. The direct labour and benefits of the stores department are directly attributable to the materials used in capital projects and therefore will continue to be eligible to be capitalized as part of the Stores burden.

The reduction in the Purchasing & Stores burden eligible to be capitalized is summarized below:

Purchasing Department Expenses	$ 229,133
Miscellaneous Stores Department Charges	$186,194
Total	$415,327

The reduction in Purchasing & Stores burden to capital projects was $340,509.

Supervisory

Included in Supervisory burden were wages and benefits of the lines superintendent, operations superintendent, power systems clerks, and linesman supervisors and other miscellaneous expenses related to the supervisory department.

Per review of the roles of the superintendents it was determined that they provided a supervisory role and therefore their charges are not eligible for capitalization. Further, the clerks provided a support role for the department and therefore their costs are not eligible for capitalization.

The PLT supervisors provided direct supervision of the PLT staff which are directly attributable to capital when applicable and therefore eligible for capitalization.

The reduction in supervisory expenses not eligible for capitalization is as follows:

Superintendents Charges	$288,252
Clerks	$ 68,852
Other Miscellaneous Department Charges	$178,487
Total	$535,591

The reduction in Supervisory burden to capital projects was $323,194.

Table 4-4.1 Impact of MCGAAP on Burdens and OM&A

Burdens		General & Administrative Labour	Labour Burden	Purchasing Department Charges	Miscellaneous Department Charges	Total Ineligible for Capitalization	Reduction in Allocation to Capital
Downtime Burden			450,586			450,586	297,382
Engineering Burden		180,210			255,720	435,930	232,559
Fleet Maintenance Burden		268,049			250,759	518,808	502,513
Stores Burden				229,133	186,194	415,327	340,509
Supervisory Burden		357,104			178,487	535,591	323,194
Total		**805,363**	**450,586**	**229,133**	**871,160**	**2,356,242**	**1,696,157**
Burden amounts reallocated							**Overhead Adjustments**
Accumulated Amortization							288,714
Operations							386,140
Maintenance							843,836
Billing & Collecting							1,876
Community Relations							0
Administration							175,592
Total							**1,696,157**

MCGAAP – IMPACT ON DEPRECIATION

IAS 16 requires each part of an item of PP&E with a cost that is significant in relation to the total cost of the time to be depreciated separately. In addition IAS 16 requires that entities perform a review of assets' useful lives, depreciation methods and residual values on an annual basis.

The OEB commissioned a depreciation study to assist electricity distributors in their transition to IFRS. In the Report of the Board, Transition to International Financial Reporting Standards, (EB-2009-0408) the Board stated:

> "While utilities remain solely responsible for complying with financial reporting requirements, the Board notes that a generic depreciation study could assist utilities with IFRS compliance in addition to providing considerable regulatory benefits. The study should provide a good starting point for the determination of service lives for distribution assets that may be both acceptable to the Board and useful for financial reporting purposes. Distributors will remain responsible for review and updates of the service lives for their particular assets for financial reporting and regulatory requirements."

Thunder Bay Hydro has reviewed the useful life of its assets with the aid of the Asset Depreciation Study by Kinetrics (Kinetrics Report). Table 4-4.2 contains the useful lives by Uniform System of Account, compared to the current useful lives used under CGAAP. Overall, the useful lives have been extended causing depreciation to be reduced in the 2013 Test year by $2,389, 509 ($5,594,342 under CGAAP to $3,204,833 under MCGAAP).

Table 4-4.2 MCGAAP Amortization Periods & Amortization Expense for 2013

OEB	Description	CGAAP Amortization Period	TUL/Useful Life Range per Kinetrics Report	MCGAAP Amortization Period	2013 MCGAAP Amortization of USofA	Explanation of Difference in Service Life from TUL
1805	**Land**	N/A	N/A	N/A	-	
1806	**Land Rights**	N/A	N/A	N/A	-	
1808	**Operations Centre**	50	50-75	50	72,044	
1808	**Garage**	50	50-75	50	25,250	
1810	**Leasehold Improvements**	5	5	5	8,399	
1820	**Distribution Station Equipment -ARO**	30	N/I	Based on estimated date of demolition	7,386	
1820	**Distribution Station Equipment - Normally Primary below 50 kV**	30	15-50	15-50	319,827	
1830	**Poles, Towers and Fixtures**	25			727,173	
	Wood Poles		40	40		
	Steel Cross Arms		70	70		
	Fibre Glass Cross Arms		NI	80		
1835	**Overhead Conductors and Devices**	25			455,881	
	Switches		45	40		40 year life used due to the fact that when the overhead pole is removed in the 40 year period the switch will also be removed and not re-used
	Primary and Neutral Cables		60	60		
	Secondary Cables		60	60		
1840	**Underground Conduit**	25			107,946	
	Trenches		N/I	40		
	Conduits		50	80		Based on actual use, TBH is able to reuse a conduit for 2 conductor installation, therefore 80 years.
	Foundations		55	55		
1845	**Underground Conductors and Devices**	25			355,182	
	Primary Cables in Duct		40	40		
	Primary Cables Direct Buried		30	30		
	Secondary Cables in Duct		35	40		40 year life based on prior actual results.
	Secondary Cables Direct Buried		30	40		
	Underground Switchgear			30		
1850	**Line Transformers**	25	40	40	558,091	
1850	**Transformer ARO**	25				
1855	**Services (Underground, Overhead)**	25	40/60	40/60	239,816	
1860	**Meters**					
	Smart Meters, Repeaters, Data Collectors		10-20	15		
	Industrial	25	25-35	35	552,176	
	Current & Potential Transformer		35-50	50		
	Primary Meter		35-50	50		
1915	**Office Furniture and Equipment**	10	5-15	10	42,182	
1920	**Computer Equipment - Hardware**	5	3-5	3/5	182,002	
1925	**Computer Software**	5	2-5	2	51,926	
1930	**Transportation Equipment**					
	Trucks & Buckets		5-15	15		
	Trailers	5/8	5-20	20	229,233	
	Vans/Cars		5-10	12		
1935	**Stores Equipment**	10	5-10	10	-	
1940	**Tools, Shop and Garage Equipment**	10	5-10	10	106,098	
1945	**Measurement and Testing Equipment**	10	5-10	10	6,919	
1950	**Power Operated Equipment**	10	5-10	10	2,306	
1955	**Communication Equipment**	5	2-10	5	9,446	
1960	**Miscellaneous Equipment**	10	5-10	10		
1980	**System Supervisory Equipment**	30	20	20	34,343	
2440	**Deferred Revenue**	25	Based on asset	40-80	(12,712)	
1995	**Contributions and Grants**	25	Based on asset	40-80	(456,959)	
1609	**Hydro One Current & Voltage Transformer Upgrades**	25	15-30	30	42,411	
	SUBTOTAL AMORTIZATION EXPENSE				**3,666,366**	
	LESS: AMORTIZATION ALLOCATION TO OTHER TRIAL BALANCE ACCOUNTS AND OVERHEADS				(431,834)	
	LESS: AMORTIZATION OF DEFERRED REVENUE				12,712	
	LESS: HYDRO ONE CURRENT & VOLTAGE TRANSFORMER UPGRADES				(42,411)	
	NET AMORTIZATION EXPENSE TO INCOME STATEMENT				**3,204,833**	

N/A Not Applicable
N/I Not Indicated in Kinetrics Study

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Review of Opening Assets Remaining Service Lives

Thunder Bay Hydro reviewed all of its existing assets as of December 31, 2011 in anticipation of adoption of IFRS for 2013. All existing infrastructure assets were reviewed to determine type of equipment existing and estimated changes to service lives.

MCGAAP – IMPACT ON TAXES

TAX CALCULATIONS

Table 4-4.3 below provides a summary of 2009, 2010, and 2011 Actual income taxes included in audited statements, and the 2012 Bridge Year (CGAAP) and 2013 Test Year (MCGAAP) income tax estimates using rates currently prescribed by Canada Revenue Agency.

Table 4-4.3 - Summary of Income & Capital Taxes 2009 to 2012 CGAAP and 2013 MCGAPP

Description	2009 Actuals Adjusted For "Non-Wires" Activity	2010 Actuals Adjsuted for "Non-Wires" Activity	2011 Actuals Adjusted for "Non-Wires" Activity	2012 Bridge CGAAP	2013 MCGAAP Test
Income Taxes - Current per Actual Returns	748,574	580,821	706,508		
Adjustment for" Non-Wires" Activity	10,427	44,522	28,552		
Income Taxes - Current	759,001	625,342	735,060	315,867	**
Less: Prior Period Adjustments	-	-	-	-	-
Ontario Capital Tax	178,000	60,000	3,752	-	-
TOTAL TAXES	937,001	685,342	738,812	315,867	-

Notes:
** 2013 Tax refund calculated as nil for COS

Thunder Bay Hydro has provided the Capital Cost Allowance and Cumulative Eligible Capital Calculation continuity schedules for the 2013 Test Year MCGAAP under Tables 4-4.4 and 4-4.5 respectively.

Table 4-4.4 - 2013 CCA Continuity Schedule MCGAAP

CCA Continuity Schedule MCGAAP (2013)

Class	Class Description	UCC Prior Year Ending Balance	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Bridge Year Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	48,015,697	0	0	48,015,697	0	0	48,015,697	0	48,015,697	4%	1,920,628	46,095,069
2	Distribution System - pre 1988	0	0	0	0	0	0	0	0	0	6%	0	0
6	Buildings - after 1990	0	0	0	0	0	0	0	0	0	10%	0	0
8	General Office/Stores Equip	786,261	0	0	786,261	250,846	0	1,037,107	125,423	911,684	20%	182,337	854,771
10	Computer Hardware/ Vehicles	1,376,318	0	0	1,376,318	960,345	12,500	2,324,163	473,923	1,850,241	30%	555,072	1,769,091
10.1	Certain Automobiles	0	0	0	0	0	0	0	0	0	30%	0	0
12	Computer Software	21,751	0	0	21,751	77,200	0	98,951	38,600	60,351	100%	60,351	38,600
3	Buildings - pre 1990	0	0	0	0	0	0	0	0	0	5%	0	0
4	Buildings	1,475,207	0	0	1,475,207	3,303,500	0	4,778,707	1,651,750	3,126,957	6%	187,617	4,591,089
13 3	Lease # 3	67,481	0	0	67,481	0	0	67,481	0	67,481	20%	13,496	53,985
13 4	Lease # 4	0	0	0	0	0	0	0	0	0		0	0
14	Franchise	0	0	0	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Hardware acq'd post Mar 22/04	4,129	0	0	4,129	0	0	4,129	0	4,129	45%	1,858	2,271
50	Computers & Systems Hardware acq'd post Mar 19/07	201,503	0	0	201,503	81,600		283,103	40,800	242,303	55%	133,267	149,836
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	0	0	0	30%	0	0
47	Distribution System - post 22-Feb-2005	38,720,337			38,720,337	8,733,924		47,454,261	4,366,962	43,087,299	8%	3,446,984	44,007,277
	SUB-TOTAL - UCC	**90,668,684**	**0**	**0**	**90,668,684**	**13,407,415**	**12,500**	**104,063,599**	**6,697,457**	**97,366,142**		**6,501,610**	**97,561,989**

Table 4-4.5 - 2013 Cumulative Eligible Capital Calculation MCGAAP

Cumulative Eligible Capital Calculation MCGAAP				
Cumulative Eligible Capital				823,926
Additions:				
Cost of Eligible Capital Property Acquired during the year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after	0	x 1/2 =	0	
			0	823,926
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				**823,926**
Deductions:				
Projected proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during the				
Other Adjustments	0			
Subtotal	**0**	**x 3/4 =**	**0**	**823,926**
Cumulative Eligible Capital Balance				823,926
CEC Deduction	7%			57,675
Cumulative Eligible Capital - Closing Balance				**766,251**

Thunder Bay Hydro has provided detailed income tax calculations using MCGAAP net income, MCGAAP amortization & MCGAAP CCA as shown in Table 4-4.6 below.

Table 4-4.6 – Detailed Income Tax Calculations for 2013 (CGAAP) and 2013 (MCGAAP)

	2013 CGAAP Test	2013 MCGAAP Test
Accounting Net Income Before Taxes	1,093,030	2,278,247
Additions		
Amortization of assets	5,948,742	3,602,233
Taxable Capital Gains	30,000	30,000
Apprenticeship Training Tax Credit	90,625	90,625
Non deductible meals	9,605	9,605
Non-deductible future benefit retirement accruals	259,266	259,266
Deductions		
Capital cost allowance from Schedule 8	6,554,067	6,502,047
Gain (Loss) on Disposal of Assets	56,170	56,170
Cumulative Eligible Capital Deduction	57,611	57,611
Future benefit premiuns paid	155,627	155,627
Capitalized portion of future benefit expenses	42,133	26,638
ARO Expense	14,627	21,151
	-	-
	-	-
Total Tax Adjustments to Accounting Income	(541,998)	(2,827,515)
Income for Tax Purposes	449,710	(549,268)
	-	-
Effective Tax Rate Reflecting Tax Credits (Federal & Provincial)	21.05%	26.50%
	-	**
Income Taxes Before Credits	116,043	-
Less: Apprenticeship Training Credit	90,625	-
Income Taxes	25,418	-
		-
Capital Tax Calculation:		
Total Rate Base	-	-
	-	-
Rate	0.000%	0.000%
Capital Tax - As Calculated	**-**	**-**
Capital Tax - As per Audited Statements	**-**	**-**

GREEN ENERGY ACT (GEA) PLAN – OM&A Costs

Thunder Bay Hydro has submitted a basic Green Energy Act Plan to the OPA and has provided a copy in Exhibit 2, Appendix 2-B. The OPA provided a Letter of Comment which has been provided in Exhibit 2, Appendix 2-C. As part of its plan, Thunder Bay Hydro has estimated only the gross capital spending requirements in 2012 and 2013. Thunder Bay Hydro has not forecasted any OM&A costs under the GEA Plan, and as a result, the funding adder calculation discussed in Exhibit 9 is strictly for the capital investment of the 6 FIT reclosers.

CONSERVATION AND DEMAND MANAGEMENT ("CDM") COSTS

Thunder Bay Hydro requests approval and recovery of historical Lost Revenue Adjustment Mechanism ("LRAM") amounts related to Conservation and Demand Management (CDM) activities in 2011. It is requested that these amounts be recovered through a rate rider over a one-year period beginning May 1, 2013. The total amount for recovery is a debit balance of $40,315, which includes carrying charges of $1,060. Amounts for LRAM recovery are summarized in Table 4-6.1.

Table 4-6.1 - Summary of Requested LRAM Amounts

Rate Class	Total LRAMVA Claim for 2011 LRAMVA Programs	Total LRAMVA Claim for 2011 LRAMVA Programs - Persistence in 2012	Total LRAM Claim	Carrying Charges	Total
	A	B	C	D	E = C+D
Residential	$13,346	$13,165	$26,511	$716	$27,226
General Service <50 kW	$6,222	$6,174	$12,395	$335	$12,730
General Service > 50 to 999 kW	$138	$138	$277	$7	$284
General Service > 1000kW	$35	$38	$72	$2	$74
Unmetered Loads	$0	$0	$0	$0	$0
Sentinel Lights	$0	$0	$0	$0	$0
Streelights	$0	$0	$0	$0	$0
TOTAL	**$19,741**	**$19,514**	**$39,255**	**$1,060**	**$40,315**

NOTES:

1. Totals may differ from the sum of rows or columns due to rounding
2. Carrying charges were calculated using OEB approved rates.

LRAM AMOUNTS

The LRAM adjusts for volumetric variances between actual CDM results and the corresponding quantities used in rate setting. The requested LRAM amounts are derived from savings composed of Ontario Power Authority ("OPA") programs implemented in 2011. The lost revenues are calculated from the year of introduction through to April 30 2013. Thunder Bay Hydro has used the most recent input assumptions in calculating the LRAM amount. The 2011 OPA Final Evaluation Report has been used in support of the LRAM calculations. A copy of the 2011 OPA Final Evaluation Report has also been submitted in Excel format as part of this application.

None of the load reductions were factored into the load forecast underpinning 2011 or 2012 rates. The calculation of the load reduction is based on the energy and demand savings and the lifespan of the technology by rate class. The reduction in demand related to these programs has been incorporated into the rate forecast for May 1, 2013 onward. However, energy savings related to OPA programs delivered in 2011 and 2012 have not been captured.

Recovery

Thunder Bay Hydro requests recovery of the LRAM amounts by way of volumetric rate rider over a one-year period, effective May 1, 2013, with the foregone revenue from each customer class allocated to that class for recovery. The debit balance of $40,315 has been included in Account 1568 of the Deferral and Variance Account file for disposal and has been included is the Deferral and Variance rate rider. Table 4-6.2 – 4-6.3 sets the corresponding amounts by class, as well as the corresponding rate rider based on forecasted 2013 volume.

Table 4-6.2: Cumulative Net Energy and Demand Savings by Rate Class through April 30 2013 from CDM Programs

Funding source	Program	Program year	Residential (kWh)	GS < 50 kW (kWh)	GS 50 to 999 kW (kW)	GS > 1,000 kW (kW)
OPA	Appliance Retirement	2011	309,783			
		Persistence in 2012	309,783			
	Appliance Exchange	2011	1,969			
		Persistence in 2012	1,969			
	HVAC Incentive	2011	352,545			
		Persistence in 2012	352,545			
	Conservation Instant Coupon Booklet	2011	166,902			
		Persistence in 2012	166,902			
	Bi-Annual Retailer Event	2011	256,791			
		Persistence in 2012	256,791			
	Efficiency: Equipment Replacement	2011		161,460	94	
		Persistence in 2012		161,460	94	
	Direct Install Lighting	2011		295,711		
		Persistence in 2012		295,711		
	Efficiency: Equipment Replacement Incentive (Part of the C&I Program Schedule)	2011				18
		Persistence in 2012				18
	Electricity Retrofit Incentive Program	2011		23,889	11	
		Persistence in 2012		23,889	11	
	High Performance New Construction	2011			1	
		Persistence in 2012			1	
Total savings			**2,175,978**	**962,118**	**210**	**36**

NOTES:

1. The source of the data in the Table above is obtained from the OPA Final CDM Results for 2011.

Table 4-6.3: Summary of LRAM Claim by Program and Rate Class

Funding source	Program	Program year	Residential	GS < 50 kW	GS 50 to 999 kW	GS > 1,000 kW	LRAM
OPA	Appliance Retirement	2011	$3,800				$3,800
		Persistence in 2012	$3,748				$3,748
	Appliance Exchange	2011	$24				$24
		Persistence in 2012	$24				$24
	HVAC Incentive	2011	$4,325				$4,325
		Persistence in 2012	$4,266				$4,266
	Conservation Instant Coupon Booklet	2011	$2,047				$2,047
		Persistence in 2012	$2,020				$2,020
	Bi-Annual Retailer Event	2011	$3,150				$3,150
		Persistence in 2012	$3,107				$3,107
	Efficiency: Equipment Replacement	2011		$2,088	$124		$2,212
		Persistence in 2012		$2,072	$124		$2,196
	Direct Install Lighting	2011		$3,825			$3,825
		Persistence in 2012		$3,795			$3,795
	Efficiency: Equipment Replacement Incentive (Part of the C&I Program Schedule)	2011				$35	$35
		Persistence in 2012				$38	$38
	Electricity Retrofit Incentive Program	2011		$309	$14		$323
		Persistence in 2012		$307	$14		$320
	High Performance New Construction	2011			$1		$1
		Persistence in 2012			$1		$1
Total savings			**$26,511**	**$12,395**	**$276**	**$72**	**$39,254**

NOTES:

1. The dollar values were calculated by using the kWh in Table 4-6.2 and multiplying the volume by the applicable Board-approved volumetric distribution charge for the year in which the programs occurred.

Table 4-6.4: LRAM Amounts and Rate Riders by Class

	LRAM	Carrying Charges	Total	Unit	2013 Forecasted Billed kWh/kW	Proposed Rate Rider
Residential	$26,511	$716	$27,226	kWh	335,941,782	0.0001
General Service <50 kW	$12,395	$335	$12,730	kWh	129,942,565	0.0001
General Service > 50 to 999 kW	$277	$7	$284	kW	774,872	0.0004
General Service > 1000kW	$72	$2	$74	kW	562,588	0.0001
Total	$39,255	$1,060	$40,315			

NOTES:

1. Totals differ from the sum of rows or columns due to rounding

Since Thunder Bay Hydro's CDM Programs are all OPA-approved programs that are included in the 2011 OPA Final Evaluation Report which has been reviewed by a third-party, Thunder Bay Hydro believes this to be sufficient review and verification of the LRAM calculations and is not providing a second third-party report in this Application.

APPENDICES

Appendix 4-A

Affiliate Services Agreement

SERVICE AGREEMENT BETWEEN

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
AND
THUNDER BAY HYDRO RENEWABLE POWER INCORPORATED

SERVICES AGREEMENT

THIS AGREEMENT made as of the **29th day of April 2009**,

BETWEEN:

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC., a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "DISTRIBUTION")

OF THE FIRST PART

- and -

THUNDER BAY HYDRO RENEWABLE POWER INCORPORATED., a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "RENEWABLE")

OF THE SECOND PART

WHEREAS DISTRIBUTION is required by the Ontario Energy Board to enter a service agreement (hereinafter referred to as the "Agreement") with RENEWABLE under the Affiliate Relationships Code for Electricity Distributors and Transmitters (revised May 16, 2008 and as may be amended from time to time) (hereinafter referred to as the "Code");

AND WHEREAS the Code provides that DISTRIBUTION and any affiliate with which it shares services, shall do so in accordance with a Services Agreement

AND WHEREAS DISTRIBUTION has agreed to share services of certain of its employees with RENEWABLE for a fee, subject to the terms and conditions set forth herein;

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the premises and agreements herein contained, it is mutually declared, covenanted and agreed by and between the parties hereto as follows:

1. SERVICES PROVIDED

(a) DISTRIBUTION shall provide management services to RENEWEABLE as RENEWABLE may reasonably require from time to time. The management services shall consist of providing direction, planning and administration in project construction and operations for RENEWABLE business functions.

(b) DISTRIBUTION shall sell all services, resources, and products to RENEWABLE at DISTRIBUTION'S fully-allocated cost to provide the service, resource, or product, which shall include the sum of (i) direct project construction and operations management costs and (ii) RENEWABLE's allocated portion of shared corporate overhead services. DISTRIBUTION shall calculate the fully-allocated cost on an annual basis and invoice RENEWABLE a fixed monthly charge accordingly.

(c) DISTRIBUTION shall not incur any third party costs in providing services to RENEWABLE without the prior written approval of RENEWABLE. RENEWABLE shall reimburse DISTRIBUTION for any third party costs incurred. DISTRIBUTION shall submit to RENEWABLE an invoice or similar evidence of payment in respect of all third party costs for which it seeks reimbursement hereunder.

(d) DISTRIBUTION shall sell assets to RENEWABLE at the greater of market price and the net book value of the asset. Before selling an asset to RENEWABLE with a net book value that exceeds $100,000 or 0.1% of DISTRIBUTION's utility revenue, whichever is greater, DISTRIBUTION shall obtain an independent assessment of its market price.

(e) DISTRIBUTION shall purchase assets from RENEWABLE at a price no more than the market price. Before DISTRIBUTION purchases an asset from RENEWABLE with a net book value that exceeds $100,000 or 0.1% of DISTRIBUTION's utility revenue, whichever is greater, the utility shall obtain an independent assessment of its market price.

(f) DISTRIBUTION may provide loans, guarantee the indebtedness of, or invest in the securities of RENEWABLE, but shall not invest or provide guarantees or any other form of financial support if the amount of support or investment, on an aggregated basis over all transactions with all affiliates, would equal an amount greater than 25% of DISTRIBUTION's total equity. In addition, the terms of any loan, investment, or other financial support provided to RENEWABLE are to be no more favourable than what RENEWABLE would be able to obtain on its own from the capital markets and in all cases at no more favourable terms than DISTRIBUTION could obtain directly for itself in capital markets.

(g) All amounts owing by RENEWABLE will be settled as incurred, or at a minimum, on a monthly basis. Both DISTRIBUTION and RENEWABLE, will settle any amounts owing within three months following the year end of DISTRIBUTION.

(h) DISTRIBUTION shall take all reasonable steps to ensure that RENEWABLE does not use DISTRIBUTION's name, logo or other distinguishing characteristics in a manner which would mislead consumers as to the distinction between DISTRIBUTION and RENEWABLE.

(i) DISTRIBUTION shall take reasonable steps to ensure that RENEWABLE does not imply in its marketing material favoured treatment or preferential access to DISTRIBUTION's system or services. If DISTRIBUTION becomes aware of inappropriate marketing activity by RENEWABLE, it shall (1) immediately take reasonable steps to notify affected customers of the violation (2) take necessary steps to ensure the affiliate is aware of the concern, and (3) inform the Board in writing of such activity and the remedial measures that were undertaken by DISTRIBUTION.

(j) Requests by RENEWABLE or RENEWABLE's customers for access to DISTRIBUTION's distribution network or for utility services shall be processed and provided by DISTRIBUTION in the same manner as would be processed or provided for similarly situatied non-affiliated parties.

2. LIMITATION OF LIABILITY

All risk arising under this Agreement and extraneous to this Agreement is with RENEWABLE. DISTRIBUTION assumes no risk. In no event shall DISTRIBUTION be liable for damages arising from risks associated with the provision of services under this Agreement or otherwise.

3. DISPUTE RESOLUTION PROCESS

Any dispute arising between DISTRIBUTION and RENEWABLE under this Agreement or arising over the terms of the Agreement shall be resolved by arbitration under the Arbitrations Act, 1991, S.O. 1991, Chapter 17.

4. TERMINATION

The term of this Agreement is on a year-to-year basis commencing on the date hereof. This Agreement may be terminated by RENEWABLE by giving written notice to DISTRIBUTION, or by DISTRIBUTION by giving written notice to RENEWABLE, given at least six months prior to any anniversary of the date hereof. Any changes in the amounts payable under this Agreement shall be changed as of January 1st in each year,

based on the change, if any, in the Consumer Price Index for Thunder Bay as of the end of October for the prior year from the previous end of October.

5. ENTIRE AGREEMENT

This Agreement contains the entire agreement amongst DISTRIBUTION and RENEWABLE and no amendment hereof shall be binding upon DISTRIBUTION and RENEWABLE unless same is in writing and signed by DISTRIBUTION and RENEWABLE. Amendments to this Agreement come into effect on the anniversary of a six-month notice period.

6. PERSONAL SERVICES AGREEMENT

This Agreement is a personal services agreement and may not be assigned by either party hereto without the prior written consent of the other party.

7. CONFIDENTIALITY

(a) Information that becomes known through the relationship between DISTRIBUTION and RENEWABLE remains confidential, and neither DISTRIBUTION nor RENEWABLE may disclose said information to any third party.

(b) All confidential information that DISTRIBUTION shares with RENEWABLE under this Agreement is to be protected from access by RENEWABLE. Access to DISTRIBUTION's information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols and the Agreement shall be ensured as necessary, through a review which complies with the provisions of Section 5970 of the Canadian Institute of Chartered Accountants Handbook (hereinafter referred to as the "CICA Handbook"). The Ontario Energy Board (hereinafter referred to as the "Board") may provide direction regarding the terms of the Section 5970 review. The results of any review shall be made available to the Board.

(c) Services to be provided by DISTRIBUTION's employees under Section 1 of this Agreement are subject to the provision that these employees are not directly involved in collecting, and do not have access to, confidential information.

(d) DISTRIBUTION shall not release to RENEWABLE confidential information relating to a smart sub-metering provider, wholesaler, consumer, retailer, or generator without the consent of that smart sub-metering provide, wholesaler, consumer, retailer, or generator.

(e) DISTRIBUTION shall not disclose confidential information to RENEWABLE without the consent in writing of the smart sub-metering provider, wholesaler, consumer, retailer, or generator, as the case may be, except where confidential information is required to be disclosed:

(i) for billing or market operation purposes;
(ii) for law enforcement purposes;
(iii) for the purpose of complying with a legal requirement; or
(iv) for the processing of past due accounts of the consumer which have been passed to a debt collection agency.

(f) Confidential information may be disclosed where the information has been sufficiently aggregated such that any individual smart sub-metering provider, wholesaler, consumer, retailer, or generator's information cannot reasonably be identified. If such information is aggregated it must be disclosed on a non-discriminatory basis to any party requesting the information.

8. DEGREE OF SEPERATION

DISTRIBUTION shall ensure accounting and financial separation from RENEWABLE and shall maintain separate financial records and books of accounts in accordance with guidelines specified in the Code.

9. QUALITY OF SERVICE

DISTRIBUTION shall meet its obligations to RENEWABLE under this Agreement by providing a quality of service at least equal to that which would be provided by an independent third party.

10. FORCE MAJEURE

"Force Majeure" means a strike, lockout, riot, insurrection, war, fire, tempest, flood, act of God, lack of materials or supply of service which results notwithstanding the diligent efforts of DISTRIBUTION. During the occurrence of an event of Force Majeure, the obligations of the party effected by such event of Force Majeure, to the extent that such obligations cannot be performed as a result of such event of Force Majeure, shall be suspended, and such a party shall not be considered to be in default hereunder, for the period of such occurrence, except that the occurrence of an event of Force Majeure affecting RENEWABLE (but not affecting the performance of DISTRIBUTION's obligations hereunder) shall not relieve it of its obligations to make payments to DISTRIBUTION hereunder. The non-performing party shall give the other party prompt written notice of the particulars of the event of Force Majeure and its expected duration and shall continue to furnish regular reports with respect thereto on a timely basis during

the continuance of the event of Force Majeure and shall use its best efforts to remedy its inability to perform. The suspension of performance is to be of no greater scope and of no longer duration than is required by the Force Majeure condition. No obligations of either Party that arose before the Force Majeure causing the suspension of performance are excused as a result of the Force Majeure.

11. TIME

Time shall be of the essence herein.

12. PREVIOUS AGREEEMENTS

This Agreement terminates, cancels and supersedes any and all other written and verbal agreements between the parties relating to these issues herein.

13. INUREMENT

This Agreement shall bind DISTRIBUTION, RENEWABLE, and their respective legal representatives, executors, administrators, successors and permitted assigns.

14(1). DEFINITIONS

All words in the Agreement are defined under Sections 1.2 and 1.3 of the Affiliate Relationships Code for Electricity Distributors and Transmitters as of its revised date May 16, 2008 (hereinafter referred to as the "Code"), unless the context otherwise requires.

14(2) APPLICATION OF THE 'AFFILIATE RELATIONSHIPS CODE" TO THE AGREEMENT

All sections of the code apply to this Agreement and are incorporated by reference.

15. CONSTRUCTION

The Agreement herein shall, in all respects, be subject to and be interpreted, construed and enforced in accordance with the laws in effect in the Province of Ontario. Each party hereto accepts the jurisdiction of the courts of the Province of Ontario and all courts of appeal therefrom.

16. HEADINGS

The headings of clauses herein are inserted for convenience or reference only and shall not affect or be considered the construction of the provisions hereof.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the date first above written.

THUNDER BAY HYDRO ELECTRICTY DISTRIBUTION INC.

Per: Cindy Bazzale

THUNDER BAY HYDRO RENEWABLE POWER INCORPORATED

Per:

SERVICE AGREEMENT BETWEEN

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.
AND
THUNDER BAY HYDRO UTILITY SERVICES INC.

SERVICES AGREEMENT

THIS AGREEMENT made as of the 30th day of June 2006,

BETWEEN:

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC., a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "DISTRIBUTION")

OF THE FIRST PART

- and -

THUNDER BAY HYDRO UTILITY SERVICES INC., a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "SERVICES")

OF THE SECOND PART

WHEREAS DISTRIBUTION is required by the Ontario Energy Board to enter a service agreement (hereinafter referred to as the "Agreement") with SERVICES under the Affiliate Relationships Code for Electricity Distributors and Transmitters (revised November 24, 2003 and as may be amended from time to time) (hereinafter referred to as the "Code");

AND WHEREAS the Code provides that DISTRIBUTION and any affiliate with which it shares services, shall do so in accordance with a Services Agreement

AND WHEREAS DISTRIBUTION has agreed to share services of certain of its employees with SERVICES for a fee, subject to the terms and conditions set forth herein;

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the premises and agreements herein contained, it is mutually declared, covenanted and agreed by and between the parties hereto as follows:

1. SERVICES PROVIDED

(a) DISTRIBUTION shall provide meter services to SERVICES as SERVICES may reasonably require from time to time. The meter services shall consist of a contract employee to service customers of the meter service provider business, a qualified meter technician on an "as is required" basis and 364 square feet of office space. All such services shall be provided on a cost recovery plus the prime rate of DISTRIBUTION'S Bank (Bank Prime Rate) adjusted quarterly. The current Prime Rate of DISTRIBUTION'S Bank is 6% per annum.

(b) DISTRIBUTION shall provide utility billing services to SERVICES as SERVICES may reasonably require from time to time and this will include download meter reading data, wholesale settlement, electronic business transaction functions, remote meter reader function, information services, customer information services, accounting services and purchasing services. These shall be provided on a cost recovery plus Bank Prime Rate adjusted quarterly, which Bank Prime Rate is presently 6% per annum.

(c) In addition to any payments made under paragraphs 1 (a) and (b), SERVICES shall reimburse DISTRIBUTION for any third party costs incurred by DISTRIBUTION in accordance with paragraphs 1 (a) and (b). DISTRIBUTION shall, if requested by SERVICES, be required to submit an invoice or similar evidence of payment in respect of all third party costs for which it seeks reimbursement hereunder.

(d) All amounts owing by SERVICES will be settled as incurred, or at a minimum, on a monthly basis. Both DISTRIBUTION and SERVICES, will settle any amounts owing within three months following the year end of Distribution

(e) All services, resources, and products sold according to paragraph 1 (b) and paragraph 1 (c) are to be sold at a minimum of the fair market value of the service, resource, or product.

(f) Where a fair market value is not available for any product, resource, or service provided under paragraph 1, DISTRIBUTION shall charge no less than a cost-based price, and shall pay no more than a cost-based price. A cost-based price shall reflect the costs of producing the service or product, including a return on invested capital. The return component shall be the higher of DISTRIBUTION's approved rate of return or the bank prime rate.

(g) DISTRIBUTION shall sell assets to SERVICES at a price no less than the net book value of the asset.

2. LIMITATION OF LIABILITY

All risk arising under this Agreement and extraneous to this Agreement is with SERVICES. DISTRIBUTION assumes no risk. In no event shall DISTRIBUTION be liable for damages arising from risks associated with the provision of services under this Agreement or otherwise.

3. DISPUTE RESOLUTION PROCESS

Any dispute arising between DISTRIBUTION and SERVICES under this Agreement or arising over the terms of the Agreement shall be resolved by arbitration under the Arbitrations Act, 1991, S.O. 1991, Chapter 17.

4. TERMINATION

The term of this Agreement is on a year-to-year basis commencing on the date hereof. This Agreement may be terminated by SERVICES by giving written notice to DISTRIBUTION, or by DISTRIBUTION by giving written notice to SERVICES, given at least six months prior to any anniversary of the date hereof. Any changes in the amounts payable under this Agreement shall be changed as of January 1st in each year, based on the change, if any, in the Consumer Price Index for Thunder Bay as of the end of October for the prior year from the previous end of October.

5. ENTIRE AGREEMENT

This Agreement contains the entire agreement amongst DISTRIBUTION and SERVICES and no amendment hereof shall be binding upon DISTRIBUTION and SERVICES unless same is in writing and signed by DISTRIBUTION and SERVICES. Amendments to this Agreement come into effect on the anniversary of a six-month notice period.

6. PERSONAL SERVICES AGREEMENT

This Agreement is a personal services agreement and may not be assigned by either party hereto without the prior written consent of the other party.

7. CONFIDENTIALITY

(a) Information that becomes known through the relationship between DISTRIBUTION and SERVICES remains confidential, and neither DISTRIBUTION nor SERVICES may disclose said information to any third party.

(b) All confidential information that DISTRIBUTION shares with SERVICES under this Agreement is to be protected from access by SERVICES. Access to DISTRIBUTION's information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols and the Agreement shall be ensured as necessary, through a review which complies with the provisions of Section 5900 of the Canadian Institute of Chartered Accountants Handbook (hereinafter referred to as the "CICA Handbook"). The Ontario Energy Board (hereinafter referred to as the "Board") may provide direction regarding the terms of the Section 5900 review. The results of any review shall be made available to the Board.

(c) Services to be provided by DISTRIBUTION's employees under Section 1 of this Agreement are subject to the provision that these employees are not directly involved in collecting, and do not have access to, confidential information.

(d) DISTRIBUTION shall not release to SERVICES confidential information relating to a consumer, retailer, or generator without the consent of that consumer, retailer, or generator.

(e) DISTRIBUTION shall not disclose confidential information to SERVICES without the consent in writing of the consumer, retailer, or generator, as the case may be, except where confidential information is required to be disclosed:

(i) for billing or market operation purposes;
(ii) for law enforcement purposes;
(iii) for the purpose of complying with a legal requirement; or
(iv) for the processing of past due accounts of the consumer which have been passed to a debt collection agency.

(f) Confidential information may be disclosed where the information has been sufficiently aggregated such that any individual consumer, retailer, or generator's information cannot reasonably be identified. If such information is aggregated it must be disclosed on a non-discriminatory basis to any party requesting the information.

8. QUALITY OF SERVICE

DISTRIBUTION shall meet its obligations to SERVICES under this Agreement by providing a quality of service at least equal to that which would be provided by an independent third party.

9. FORCE MAJEURE

"Force Majeure" means a strike, lockout, riot, insurrection, war, fire, tempest, flood, act of God, lack of materials or supply of service which results notwithstanding the diligent efforts of DISTRIBUTION. During the occurrence of an event of Force Majeure, the obligations of the party effected by such event of Force Majeure, to the extent that such obligations cannot be performed as a result of such event of Force Majeure, shall be suspended, and such a party shall not be considered to be in default hereunder, for the period of such occurrence, except that the occurrence of an event of Force Majeure affecting SERVICES (but not affecting the performance of DISTRIBUTION's obligations hereunder) shall not relieve it of its obligations to make payments to DISTRIBUTION hereunder. The non-performing party shall give the other party prompt written notice of the particulars of the event of Force Majeure and its expected duration and shall continue to furnish regular reports with respect thereto on a timely basis during the continuance of the event of Force Majeure and shall use its best efforts to remedy its inability to perform. The suspension of performance is to be of no greater scope and of no longer duration than is required by the Force Majeure condition. No obligations of either Party that arose before the Force Majeure causing the suspension of performance are excused as a result of the Force Majeure.

10. TIME

Time shall be of the essence herein.

11. PREVIOUS AGREEEMENTS

This Agreement terminates, cancels and supersedes any and all other written and verbal agreements between the parties relating to these issues herein.

12. INUREMENT

This Agreement shall bind DISTRIBUTION, SERVICES, and their respective legal representatives, executors, administrators, successors and permitted assigns.

13(1). DEFINITIONS

All words in the Agreement are defined under Sections 1.2 and 1.3 of the Affiliate Relationships Code for Electricity Distributors and Transmitters as of its revised date February 1, 2001 (hereinafter referred to as the "Code"), unless the context otherwise requires.

13(2) APPLICATION OF THE 'AFFILIATE RELATIONSHIPS CODE" TO THE AGREEMENT

All sections of the code apply to this Agreement and are incorporated by reference.

14. CONSTRUCTION

The Agreement herein shall, in all respects, be subject to and be interpreted, construed and enforced in accordance with the laws in effect in the Province of Ontario. Each party hereto accepts the jurisdiction of the courts of the Province of Ontario and all courts of appeal therefrom.

15. HEADINGS

The headings of clauses herein are inserted for convenience or reference only and shall not affect or be considered the construction of the provisions hereof.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the date first above written.

THUNDER BAY HYDRO ELECTRICTY DISTRIBUTION INC.

Per: _____

Per: _____

THUNDER BAY HYDRO UTILITY SERVICES INC.

Per: _____

Per: _____

SERVICE AGREEMENT BETWEEN

THUNDER BAY HYDRO HYDRO CORPORATION
AND
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

SERVICES AGREEMENT

THIS AGREEMENT made as of the **29th day of June 2012**,

BETWEEN:

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC., a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "DISTRIBUTION")

OF THE FIRST PART

- and -

THUNDER BAY HYDRO CORPORATION, a corporation incorporated under the *Ontario Business Corporations Act*, R.S.O. 1990, c. B.18 (hereinafter referred to as "HYDRO CORP")

OF THE SECOND PART

WHEREAS DISTRIBUTION is required by the Ontario Energy Board to enter a service agreement (hereinafter referred to as the "Agreement") with HYDRO CORP under the Affiliate Relationships Code for Electricity Distributors and Transmitters (revised March 15, 2010 and as may be amended from time to time) (hereinafter referred to as the "Code");

AND WHEREAS the Code provides that DISTRIBUTION and any affiliate with which it shares services, shall do so in accordance with a Services Agreement

AND WHEREAS DISTRIBUTION has agreed to share services of certain of its employees with HYDRO CORP for a fee, subject to the terms and conditions set forth herein;

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the premises and agreements herein contained, it is mutually declared, covenanted and agreed by and between the parties hereto as follows:

1. SERVICES PROVIDED

(a) DISTRIBUTION shall provide management services to HYDRO CORP as HYDRO CORP may reasonably require from time to time. The management services shall consist of providing direction, planning and administration in project construction and operations for HYDRO CORP business functions.

(b) DISTRIBUTION shall sell all services, resources, and products to HYDRO CORP at DISTRIBUTION'S fully-allocated cost to provide the service, resource, or product, which shall include the sum of (i) direct project construction and operations management costs and (ii) HYDRO CORP's allocated portion of shared corporate overhead services. DISTRIBUTION shall calculate the fully-allocated cost on an annual basis and invoice HYDRO CORP a fixed monthly charge accordingly.

(c) DISTRIBUTION shall not incur any third party costs in providing services to HYDRO CORP without the prior written approval of HYDRO CORP. HYDRO CORP shall reimburse DISTRIBUTION for any third party costs incurred. DISTRIBUTION shall submit to HYDRO CORP an invoice or similar evidence of payment in respect of all third party costs for which it seeks reimbursement hereunder.

(d) DISTRIBUTION shall sell assets to HYDRO CORP at the greater of market price and the net book value of the asset. Before selling an asset to HYDRO CORP with a net book value that exceeds $100,000 or 0.1% of DISTRIBUTION's utility revenue, whichever is greater, DISTRIBUTION shall obtain an independent assessment of its market price.

(e) DISTRIBUTION shall purchase assets from HYDRO CORP at a price no more than the market price. Before DISTRIBUTION purchases an asset from HYDRO CORP with a net book value that exceeds $100,000 or 0.1% of DISTRIBUTION's utility revenue, whichever is greater, the utility shall obtain an independent assessment of its market price.

(f) DISTRIBUTION may provide loans, guarantee the indebtedness of, or invest in the securities of HYDRO CORP, but shall not invest or provide guarantees or any other form of financial support if the amount of support or investment, on an aggregated basis over all transactions with all affiliates, would equal an amount greater than 25% of DISTRIBUTION's total equity. In addition, the terms of any loan, investment, or other financial support provided to HYDRO CORP are to be no more favourable than what HYDRO CORP would be able to obtain on its own from the capital markets and in all cases at no more favourable terms than DISTRIBUTION could obtain directly for itself in capital markets.

(g) All amounts owing by HYDRO CORP will be settled as incurred, or at a minimum, on a monthly basis. Both DISTRIBUTION and HYDRO CORP will settle any amounts owing within three months following the year end of DISTRIBUTION.

(h) DISTRIBUTION shall take all reasonable steps to ensure that HYDRO CORP does not use DISTRIBUTION's name, logo or other distinguishing characteristics in a manner which would mislead consumers as to the distinction between DISTRIBUTION and HYDRO CORP.

(i) DISTRIBUTION shall take reasonable steps to ensure that HYDRO CORP does not imply in its marketing material favoured treatment or preferential access to DISTRIBUTION's system or services. If DISTRIBUTION becomes aware of inappropriate marketing activity by HYDRO CORP, it shall (1) immediately take reasonable steps to notify affected customers of the violation (2) take necessary steps to ensure the affiliate is aware of the concern, and (3) inform the Board in writing of such activity and the remedial measures that were undertaken by DISTRIBUTION.

(j) Requests by HYDRO CORP or HYDRO CORP's customers for access to DISTRIBUTION's distribution network or for utility services shall be processed and provided by DISTRIBUTION in the same manner as would be processed or provided for similarly situated non-affiliated parties.

2. LIMITATION OF LIABILITY

All risk arising under this Agreement and extraneous to this Agreement is with HYDRO CORP. DISTRIBUTION assumes no risk. In no event shall DISTRIBUTION be liable for damages arising from risks associated with the provision of services under this Agreement or otherwise.

3. DISPUTE RESOLUTION PROCESS

Any dispute arising between DISTRIBUTION and HYDRO CORP under this Agreement or arising over the terms of the Agreement shall be resolved by arbitration under the Arbitrations Act, 1991, S.O. 1991, Chapter 17.

4. TERMINATION

The term of this Agreement is on a year-to-year basis commencing on the date hereof. This Agreement may be terminated by HYDRO CORP by giving written notice to DISTRIBUTION, or by DISTRIBUTION by giving written notice to HYDRO CORP, given at least six months prior to any anniversary of the date hereof. Any changes in the amounts payable under this Agreement shall be changed as of January 1st in each year, based on the change, if any, in the Consumer Price Index for Thunder Bay as of the end of October for the prior year from the previous end of October.

5. ENTIRE AGREEMENT

This Agreement contains the entire agreement amongst DISTRIBUTION and HYDRO CORP and no amendment hereof shall be binding upon DISTRIBUTION and HYDRO CORP unless same is in writing and signed by DISTRIBUTION and HYDRO CORP. Amendments to this Agreement come into effect on the anniversary of a six-month notice period.

6. PERSONAL SERVICES AGREEMENT

This Agreement is a personal services agreement and may not be assigned by either party hereto without the prior written consent of the other party.

7. CONFIDENTIALITY

(a) Information that becomes known through the relationship between DISTRIBUTION and HYDRO CORP remains confidential, and neither DISTRIBUTION nor HYDRO CORP may disclose said information to any third party.

(b) All confidential information that DISTRIBUTION shares with HYDRO CORP under this Agreement is to be protected from access by HYDRO CORP. Access to DISTRIBUTION's information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols and the Agreement shall be ensured as necessary, through a review which complies with the provisions of Section 5970 of the Canadian Institute of Chartered Accountants Handbook (hereinafter referred to as the "CICA Handbook"). The Ontario Energy Board (hereinafter referred to as the "Board") may provide direction regarding the terms of the Section 5970 review. The results of any review shall be made available to the Board.

(c) Services to be provided by DISTRIBUTION's employees under Section 1 of this Agreement are subject to the provision that these employees are not directly involved in collecting, and do not have access to, confidential information.

(d) DISTRIBUTION shall not release to HYDRO CORP confidential information relating to a smart sub-metering provider, wholesaler, consumer, retailer, or generator without the consent of that smart sub-metering provide, wholesaler, consumer, retailer, or generator.

(e) DISTRIBUTION shall not disclose confidential information to HYDRO CORP without the consent in writing of the smart sub-metering provider, wholesaler, consumer, retailer, or generator, as the case may be, except where confidential information is required to be disclosed:

(i) for billing or market operation purposes;
(ii) for law enforcement purposes;
(iii) for the purpose of complying with a legal requirement; or
(iv) for the processing of past due accounts of the consumer which have been passed to a debt collection agency.

(f) Confidential information may be disclosed where the information has been sufficiently aggregated such that any individual smart sub-metering provider, wholesaler, consumer, retailer, or generator's information cannot reasonably be identified. If such information is aggregated it must be disclosed on a non-discriminatory basis to any party requesting the information.

8. DEGREE OF SEPERATION

DISTRIBUTION shall ensure accounting and financial separation from HYDRO CORP and shall maintain separate financial records and books of accounts in accordance with guidelines specified in the Code.

9. QUALITY OF SERVICE

DISTRIBUTION shall meet its obligations to HYDRO CORP under this Agreement by providing a quality of service at least equal to that which would be provided by an independent third party.

10. FORCE MAJEURE

"Force Majeure" means a strike, lockout, riot, insurrection, war, fire, tempest, flood, act of God, lack of materials or supply of service which results notwithstanding the diligent efforts of DISTRIBUTION. During the occurrence of an event of Force Majeure, the obligations of the party effected by such event of Force Majeure, to the extent that such obligations cannot be performed as a result of such event of Force Majeure, shall be suspended, and such a party shall not be considered to be in default hereunder, for the period of such occurrence, except that the occurrence of an event of Force Majeure affecting HYDRO CORP (but not affecting the performance of DISTRIBUTION's obligations hereunder) shall not relieve it of its obligations to make payments to DISTRIBUTION hereunder. The non-performing party shall give the other party prompt written notice of the particulars of the event of Force Majeure and its expected duration and shall continue to furnish regular reports with respect thereto on a timely basis during the continuance of the event of Force Majeure and shall use its best efforts to remedy its inability to perform. The suspension of performance is to be of no greater scope and of no longer duration than is required by the Force Majeure condition. No obligations of either Party that arose before the Force Majeure causing the suspension of performance are excused as a result of the Force Majeure.

11. TIME

Time shall be of the essence herein.

12. PREVIOUS AGREEEMENTS

This Agreement terminates, cancels and supersedes any and all other written and verbal agreements between the parties relating to these issues herein.

13. INUREMENT

This Agreement shall bind DISTRIBUTION, HYDRO CORP, and their respective legal representatives, executors, administrators, successors and permitted assigns.

14(1). DEFINITIONS

All words in the Agreement are defined under Sections 1.2 and 1.3 of the Affiliate Relationships Code for Electricity Distributors and Transmitters as of its revised date March 15, 2012 (hereinafter referred to as the "Code"), unless the context otherwise requires.

14(2) APPLICATION OF THE 'AFFILIATE RELATIONSHIPS CODE" TO THE AGREEMENT

All sections of the code apply to this Agreement and are incorporated by reference.

15. CONSTRUCTION

The Agreement herein shall, in all respects, be subject to and be interpreted, construed and enforced in accordance with the laws in effect in the Province of Ontario. Each party hereto accepts the jurisdiction of the courts of the Province of Ontario and all courts of appeal therefrom.

16. HEADINGS

The headings of clauses herein are inserted for convenience or reference only and shall not affect or be considered the construction of the provisions hereof.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the date first above written.

THUNDER BAY HYDRO ELECTRICTY DISTRIBUTION INC.

Per: Andy Spizale

THUNDER BAY HYDRO CORPORATION

Per:

Appendix 4-B

Procurement Policy

FINANCE DIVISION
PURCHASING DEPARTMENT

PURCHASING POLICIES

JANUARY 2008

Prepared by _____ Date _____
Rosemary Pietrzyk, HB.Comm
Manager, Purchasing & Stores

Reviewed by _____ Date _____
Cindy Speziale, CA
Vice President, Finance

Authorized by _____ Date _____
Robert Mace, MBA
President

REVISION HISTORY

REV. NO	ISSUE DATE (Revised)	PREPARED BY	REVIEWED BY AND DATE	APPROVED BY AND DATE	DESCRIPTION OF REVISION
	January 2008	R. Pietrzyk	C. Speziale	R. Mace	Original Issue
01	January 27/09	C. Speziale	C.S. on 27/01/09		Policy 5.6.3-Insurance Requirements increased
02	January 24, 2011	J. Dosen			Changed GST and PST to HST throughout document
03					
04					

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Our Vision

Thunder Bay Hydro is people working together, providing services of the best value and quality to our customers.

Our Values

At Thunder Bay Hydro, we….

are committed to continually improving our level of service to all our customers, internal and external.

will treat all individuals with respect, fairness, trust and dignity.

strive to respond to customer and employee concerns effectively.

emphasize our commitment to safety, training and respect for the environment.

will develop and implement leading edge technology to benefit our customers.

Our Motto

"COMMITTED TO CUSTOMER SATISFACTION"

A STATEMENT OF ETHICS FOR PUBLIC PURCHASERS

Thunder Bay Hydro is a member of the Ontario Public Buyers Association and supports the following code of ethics. These ethics shall be adhered to by all persons with Thunder Bay Hydro who are authorized to procure goods and/or services in any capacity.

1. Open and Honest Dealings with Everyone who is involved in the Purchasing Process. This includes all businesses with which Thunder Bay Hydro contracts or from which it purchases goods and/or services.

2. Fair and Impartial Award Recommendations for All Contracts and Tenders. Thunder Bay Hydro does not extend preferential treatment to any vendor, including local companies. Referencing the Province of Ontario's Discriminatory Business Practices Act (R.S.O. 1990), granting preference to local vendors cannot be undertaken. Moreover, it is not good business practice since it limits fair and open competition for all vendors and is therefore a detriment to obtaining the best possible value for Thunder Bay Hydro.

3. An Irreproachable Standard of Personal Integrity on the Part of all those Designated as Purchasing Representatives for Thunder Bay Hydro. Absolutely no gifts or favours are accepted by the purchasing representatives of Thunder Bay Hydro in return for business or the consideration of business. Furthermore, the purchasing representatives of Thunder Bay Hydro do not publicly endorse one company in order to give that company an advantage over others.

4. Cooperation with Other Public Agencies in Order to Obtain the Best Possible Value for Every Tax Dollar. Thunder Bay Hydro is a member of a cooperative purchasing group. Made up of several public agencies, this group pools its expertise and resources in order to practice good value analysis and where possible, purchase goods and/or services in volume and save tax dollars.

1.0 CORPORATE PURCHASING POLICY

1.1 POLICY STATEMENT

It is the purpose of this policy to ensure that the Purchasing Department procure the required quality and quantity of material, supplies and services for all users in the most cost effective, timely and efficient manner and is objective and equitable in its treatment of all vendors. This policy has been developed based upon Thunder Bay Hydro's Visions and Values and The Ontario Public Buyers Association's Code of Ethics.

1.2 PURCHASING OBJECTIVES

1. To make procurement decisions using a competitive process that is open, transparent, and fair, maintaining the highest standard of ethics, and ensuring the objective and equitable treatment of all vendors.

2. To acquire by purchase, rental or lease, the required quality and quantity of materials, supplies and services (including professional and consulting services) in an efficient and cost effective manner in accordance with the Corporately approved Purchasing Policies.

3. To develop and maintain sound business relationships with suppliers in order to ensure good communications, advance information on new products, alternative supplies, improved quality, potential cost savings, and improved safety.

4. To monitor and disseminate information to user departments (lead time, back order information) on the economic climate which may have an impact on Thunder Bay Hydro and to determine the appropriate actions to be taken through Purchasing Policies and Procedures.

5. To procure necessary goods and services with due regard to the preservation of the natural environment and to encourage the use of "environmentally friendly" products and services.

6. To maintain, develop, and update a list of qualified vendors.

7. To maintain an efficient level of inventory.

1.3 GENERAL CONDITIONS

1. The Manager, Purchasing & Stores, shall exercise general supervision and control over the procurement of all goods and services in accordance with the Purchasing Policies and Procedures and shall be responsible for providing all necessary advice and services required for such purchases in accordance with the method of purchase authorized by the Purchasing Policy.

2. Generally, all acquisitions shall be in accordance with the approved departmental budgets and estimates.

3. The expenditure must be related to a whole job or complete job, item or service. No requirement for goods and services may be divided into two or more parts to avoid the provisions of this policy.

4. Thunder Bay Hydro shall be under no obligation to accept the lowest bid or any bid received in response to an informal/formal quotation, tender or proposal call. When using this privilege clause, the specific reasons the bid(s) may not be accepted must be stated.

5. The Manager, Purchasing & Stores, in consultation with the Department Manager/ Supervisor of the Requisitioning Department, may remove a vendor's name from the list of bidders for a period of up to two years on the basis of documented poor performance, non-performance or conflict of interest. A written notice of the decision will be provided to the vendor by the Manager, Purchasing & Stores.

1.4 RESTRICTIONS

The following activities are <u>restricted</u>, unless specifically approved by the President:

1. The segmenting of any purchase (goods or services) to avoid the requirements of the Policy by any method, which includes purchases made using procurement corporate credit cards.

2. The purchase or offer to purchase by an employee of Thunder Bay Hydro of any goods and/or services, except in accordance with this Policy.

3. Purchase by Thunder Bay Hydro of any goods or services for <u>personal use</u> by or on behalf of any member of the Board, employees of Thunder Bay Hydro or immediate families.

4. Where an employee involved in the award of any contract, either on his or her own behalf or while acting for, by, with or through another person, has any pecuniary interest, direct or indirect, in the Contract, the employee:

    a. shall immediately disclose the interest to the Vice President of the Division involved in the award of the contract and shall describe the general nature thereof;
    b. shall not take part in the award of the contract; and
    c. shall not attempt in any way to influence the award of the contract.

1.5 EXCLUSIONS

Those items listed in Appendix A - Recurring or Non-Competitive Expenditures, Page 51, are exempt from the requirements of the Purchasing Policies. Approval authorities are required.

2.0 PURCHASING DEPARTMENT RESPONSIBILITIES

2.1 PURCHASING DEPARTMENT RESPONSIBILITIES

1. Ensure that business transactions are conducted ethically and professionally.

2. Be responsible for the administration of the Corporate Purchasing Policies, Guidelines and Procedures, and continually review the corporate use of goods and/or services to ensure the company is receiving the best quality, quantity, service, price, etc.

3. Review purchase requisitions for completeness.

4. Determine the best method of obtaining competitive bids in conjunction with Policy 4.3 - General Procurement, Page 12.

5. Review and advise on specifications and prequalifications for potential purchasing concerns and the practicability of specifications to ensure a maximum number of competitive bids and vendor's ability to supply.

6. Consult with the requisitioner for possible advantageous changes i.e. quantity price breaks, material substitutions, standard shelf items, market conditions with regard to lead time availability, lease/purchase considerations.

7. Ensure that qualified vendors who have expressed an interest in doing business with Thunder Bay Hydro receive requests for Quotations, Tenders, and Proposals and Prequalifications, where required.

8. Prepare bid documents including contract documents, as required.

9. Prepare and issue Purchase Orders.

10. Provide training and documentation of the Purchasing P/I module to users of the system. Provide copies of the policies and procedures to all staff that have been delegated purchasing authority and training to ensure clear understanding of the corporate expectations.

11. Maintain records of business transactions as required for legal and statutory purposes.

12. Maintain an efficient level of inventory.

13. Pursue opportunities to further their knowledge of good public purchasing principles and to maintain excellent skills.

3.0 DEFINITIONS

In this policy,

"Acquisition Method" means the process by which goods or services are procured.

"Approval" means authorization to proceed with the purchase and/or services and/or disposal of goods.

"Award" means authorization to proceed with the purchase of materials, supplies and services from a chosen supplier.

"Bid" means an offer or submission from a vendor in response to a request for quotation, tender or proposal, which is subject to acceptance or rejection.

"Bid Deposit" means currencies, certified cheques, bond surety issued by a surety company or other form of negotiable instrument to ensure the successful bidder will enter into an agreement.

"Bid Irregularity" means a deviation between the requirements (terms, conditions, specifications, special instructions) of a bid request and the information provided in a bid response (Reference Appendix J – Purchasing Guidelines Regarding Bid Irregularities, Page 90).

"Bid Request" means a formal request for bids or a solicitation, which may be in the form of a Request for Quotation, Request for Tender or Request for Proposal.

"Blanket Purchase Order" (Reference "Outline Agreement", Page 7).

"Capital Expenditures" The purpose of capitalizing expenditures is to provide for an equitable allocation of cost among existing and future customers. As assets are expected to provide future economic benefits, expenditures incurred for the acquisition, construction or development of assets should be capitalized and allocated over the asset's estimated useful life. Specifically, an asset must have these characteristics:

(a) they embody a future benefit that involves a capacity to provide services (the future period must be identifiable and be greater than one year);
(b) held for use in the supply of services (poles, meters, etc.), for rental to others (i.e. water heaters) for administrative purposes (i.e. office furniture) or for the development, construction, maintenance or repair of other capital assets (i.e. chain saws);
(c) have been acquired, constructed or developed with the intention of being used on a continuing basis (i.e. construction signs, battery powered cable cutters, etc.)
(d) are not intended for sale in the ordinary course of business.

As a general rule of thumb, we do not capitalize individuals items costing less than $500 ($1,000 for computer hardware/software as their anticipate life is a much shorter time frame).

The harder judgement call comes in the determination of “betterment” versus “repair”. A “betterment” is defined as the cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced when there is an increase in the previously assessed service capacity, associated operating costs are lowered, the useful life is extended or the quality of output is improved (i.e. a refurbished transformer or meter). A “repair” is defined as the cost incurred in the maintenance of the service potential of a capital asset. Betterments should be capitalized versus repairs which are expensed currently.

“Centralized Purchasing” refers to the activities conducted by the Purchasing function in Finance and Corporate Services, which is responsible for the purchase of all goods and/or services in accordance with the requirements of these policies.

“Competitive Method” means an acquisition method where vendors are given an equal opportunity to submit bids in accordance with Thunder Bay Hydro policy and procedures.

“Contract” means a formal legal agreement by way of a purchase order or other agreement.

“Cooperative Purchasing” means coordination of Thunder Bay Hydro purchases with purchases from other not for profit organizations such as other municipalities, utility companies, school boards, hospitals, etc.

“Consulting and Professional Services” includes architects, engineers, designers, surveyors, accountants, auditors, lawyers and any other consulting and professional services rendered on behalf of Thunder Bay Hydro. These professionals should possess a current member status /accreditation in their appropriate professional body.

“Emergency” means a situation, or a threat of an impending situation, where the immediate acquisition of goods or services is essential to prevent serious delays, injury, damage, or to restore or maintain essential service to a minimum level.

“Emergency Method” means a procurement process where the usual competitive acquisition rules are suspended due to the prevailing emergency circumstance(s).

“Execute” means to legally bind Thunder Bay Hydro to the terms and conditions defined within the Purchase Order and/or Agreement.

“Expanded Works” means approved construction projects in which an unexpected problem arises during construction, which does not expand the scope of the project but is necessary in order to deliver the original approved work.

“Goods” includes supplies, equipment, materials, structures and fixtures to be delivered, installed or constructed, including the Recurring or Non-Competitive Expenditures (Reference Appendix A-Recurring or Non-Competitive Expenditures, Page 51).

“Guideline” means a statement of policy or procedure by which to determine a course of action.

“Labour and Material Bond” means a bond issued by a surety company to ensure that the contractor will pay his or her suppliers and thereby protects Thunder Bay Hydro against items which might be granted to supplier should the contractor not make proper payments.

“Lowest Acceptable Bid” means the lowest price submitted which meets the requirements and specifications as set out in the bid request, minor deviations excepted.

“Lowest Total Cost” is the cost, after all factors of price, quality, terms and conditions, service, warranty, residual costs, replacement and disposal costs are considered, that results in the lowest cost of purchase, ownership, or operation over the life of the product or service to Thunder Bay Hydro.

“Negotiation” means the action or process of conferring with one or more vendors leading to an agreement on the acquisition of the required goods and services under the conditions outlined in this Policy.

“Negotiation Method” means an acquisition method whereby Thunder Bay Hydro may confer with one or more vendors leading to an agreement on needed goods and services under the conditions outlined in this Policy.

“Non-Competitive Procurement” means sole sourcing and single sourcing.

“Outline Agreement” means any contract for the purchase of goods and services which will be required frequently or repetitively but where the exact quantity of goods and services required may not be precisely known or the time period during which the goods and services are to be delivered may not be precisely determined.

“Performance Bond” means a bond issued by a surety company on Thunder Bay Hydro executed in connection with a contract and which secures the performance and fulfillment of the undertakings, covenants, terms, conditions and agreements contained in the contracts.

“Policy” means a course of action intended to influence and determine decisions, actions and other matters.

“Prequalification” is a procurement process used to prequalify vendors for subsequent participation in an invitational Request for Proposal or Request for Quotation/Tender. Responses from proponents are evaluated against selection criteria set out in the solicitation, and a short-list of prequalified proponents is created.

“Procure”/”Procurement”/”Purchase” means to acquire by purchase, rental or lease of goods and/or service.

“Procedure” means a series of steps taken to accomplish an end or a set of established forms or methods for conducting the affairs of an organized business.

“Proposal” (Request for Proposal/RFP) means an offer to provide goods or services to Thunder Bay Hydro where it is not practical to prepare precise specifications, or where “alternatives” to detailed specifications will be considered, which may be subject to further negotiation. This process allows vendors to propose solutions to arrive at the end product, and allows for evaluation on criteria other than price.

“Purchase Order” means a written offer to a supplier formally stating all terms and conditions for purchase of goods and/or services or a written acceptance of an offer.

“Purchase Requisition” means an online request for procuring goods and/or services initiated by the user, for which budget approval has been granted.

“Quotation” means a request for prices on specific goods and/or services from selected vendors which are submitted verbally, in writing or transmitted by facsimile as specified in the Request for Quotation.

“Recommendation to Purchase” (RTP) means approval is required by the Manager, Purchasing & Stores, and may be required by the Vice President, Finance and President, to proceed with the purchase (Reference Section 4.3-General Procurement, Page 12, for circumstances where RTP is required).

“Request for Proposal/RFP” means a formal request for details on the supply of goods or the provision of services, which cannot be fully defined or specified at the time of the request.

“Requisitioner” means the person requesting the purchase of the good and/or service.

“Risk Management” is a systematic approach to setting the best course of action under uncertainty by identifying, assessing, understanding, acting on, monitoring and communicating risk issues (Reference Appendix F-Contractor Risk Assessment Form, Page 76).

“Sealed Bid” means a formal sealed response received as part of a quotation, tender or proposal.

“Services” means all professional, consulting, construction or maintenance services, including the “Recurring or Non-Competitive Expenditures” (Reference Appendix A-Recurring or Non-Competitive Expenditures, Page 51).

“Single Source” means there is more than one source in the open market but only one of these is recommended for consideration in a contract.

“Specification” means a set of requirements or descriptions containing all of the details of the item or service required. This can be as basic as a one-line description or as complex as a set of engineering specifications complete with drawings.

A specification can be either “performance based” whereby the specifier restricts the text to stating the performance that must be achieved, or “prescriptive” whereby the specifier details specific products.

“Sole Source” means the procurement of a good or service is unique to a particular vendor and cannot be obtained from another source.

“Terms of Reference” are contained in a “Request for Proposal” (RFP) document and provide proponents with the information they need to evaluate and understand the requirements of the work to which the RFP refers. Establishing satisfactory “terms of reference” involves such examples as convening a selection committee, establishing selection criteria, describing the job, disclosing the purpose for the work or services to be provided, defining the overall objective and goals to be accomplished.

“Tender” means a formal request for sealed bids for the supply of goods and/or services.

“Time-Sensitive” means a situation for which the timing to initiate and/or complete the purchase is paramount but the time available to follow normal procedures is insufficient.

“Total Acquisition Cost” means the Contract amount shall be the estimated Total Acquisition Cost less any rebates.

“Total Purchase Price” means the total final cost including all related expenses and taxes, and inclusive of any rebates or shared costs by a third party to the agreement.

“Vendor”/”Supplier” means any individual or organization providing goods or services to Thunder Bay Hydro including, but not limited to contractors, consultants, service organizations, etc.

4.0 GENERAL OVERVIEW OF PROCUREMENT

4.1 TYPES AND GOALS OF PROCUREMENT PROCESSES

Consideration	Competitive Process Seeking Multiple Bids or Proposals				Non-Competitive Procurement
	Request for Proposal	**Request for Tender**	**Request for Quotation (formal)**	**Informal, Low Value Procurement**	
Key Goals	To implement an effective, objective, fair, open, transparent, accountable and efficient process for obtaining unique proposals designed to meet **broad outcomes to a complex problem or need for which there is no clear or single solution**. To select the proposal that earns the highest score and meets the requirements specified in the competition, based on qualitative, technical and pricing considerations.	To implement an effective, objective, fair, open, transparent, accountable and efficient process for obtaining competitive bids based on <u>precisely</u> defined requirements for which a clear or single solution exists. To accept the lowest bid meeting the requirements specified in the competition.	Same as Request for Tender, except that bid solicitation is done primarily on an invitational bid. To accept the lowest bid meeting the requirements specified in the competition.	To obtain competitive pricing for a one-time procurement in an expeditious and cost effective manner through phone, fax, e-mail, other similar communication, i.e. Vendor advertisements or vendor catalogues. Informal bid is requested from known suppliers. To accept the lowest bid meeting the requirements specified in the competition.	To allow for procurement in an efficient and timely manner without seeking competitive pricing. Allows for sole sourcing purchase by negotiations, p-card purchases.

4.2 CIRCUMSTANCES FOR USE OF PROCUREMENT PROCESSES

Consideration	Competitive Process Seeking Multiple Bids or Proposals				Non-Competitive Procurement
	Request for Proposal	**Request for Tender**	**Request for Quotation (formal)**	**Informal, Quotation**	
Dollar value of procurement	Low to High Value	Medium to High Value	Low to Medium Value	Low Value	Any value, subject to proper authorization and to guidelines as outlined in Policy #1, Non-Competitive Purchases
Requisitioner has a clear or single solution in mind and precisely defines technical requirements for evaluating bids or proposals	Rarely	Always			
In evaluating bids/proposals from qualified bidders, price is the primary factor and is not negotiated	Low to Moderate Likelihood	Always			Not Applicable

4.3 GENERAL PROCUREMENT

4.3.1 AUTHORITIES

The authority for approval of purchase requisitions by dollar range values is set by the Supervisor of the Department.

4.3.2 GUIDELINES FOR METHOD OF PURCHASE

In all cases where:

1. Funds are not budgeted for the purchase and/or;
2. Low price to specification is not being recommended by the requisitioner and/or;
3. Only one (1) bid is received and/or;
4. The commodity or service is being sole- or single sourced; and/or
5. The cost of the tendered good or service exceeds the budgeted amount by more than 20%;

The additional requirements are:

1. A "Recommendation to Purchase" (RTP) is mandatory and prepared by the Purchasing Department (Reference Section 5.11, Policy #11-Recommendation to Purchase (RTP), Page 34);
2. This "RTP" requires approval from the Manager, Purchasing & Stores and may require Vice President, Finance approval, and the President's approval;

Value ranges defined in this section are **inclusive** of all delivery charges and **exclusive** of HST.

A. GOODS

1. **Purchase Card (P-Card)**: Low Dollar Value Procurements - Value Range > $0 up to and including $1,000.

This method of purchase is non-competitive and, as such, may be sole-or single sourced by the Purchaser.

This purchasing function has been decentralized to the Purchaser, therefore, it is the responsibility of the respective departmental Manager to ensure that the Purchasing Card Policy is adhered to (Reference Section 5.16, Policy #16-Purchasing Card Policy and Procedures, Page 41).

i) **With the exception of the purchase of services, "Part C" capital expenditures and material held in Thunder Bay Hydro Stores inventory,** the purchaser is authorized to procure goods by way of a P-Card in the stated value range. No purchase requisition is required.

Responsibility of the Purchaser:

1. Funds must be budgeted for.

2. The requirement (specification) shall be defined by the Purchaser.

3. Firm pricing shall be requested by the Purchaser prior to the purchase being transacted.

4. The P-Card "Purchases Record Form" (Reference Appendix O-Purchasing Card purchases Record, Page 97) shall be completed by the Purchaser, approved by the Purchaser's Supervisor and then forwarded to the Manager, Purchasing & Stores.

5. The Purchaser is responsible for addressing and resolving any issue regarding the purchase with the vendor, for example, price discrepancies, delivery issues.

Responsibility of the Purchasing Department:

1. The Manager, Purchasing & Stores, shall review the P-Card "Purchases Record Form" to ensure adherence to the Purchasing Policy.

ii) **When a Purchase Card (P-Card) is not accepted by a vendor,** the Purchaser may request a purchase order number from the Purchasing Department. The Purchaser shall verbally provide the vendor with the purchase order number to expedite the procurement/ordering process.

Responsibility of the Purchaser

1. To complete a requisition, describing the requirement, noting the quantity and firm unit price. In the "Comments Section" (F8) of the requisition, the following information shall be documented:

   a. "Confirming P.O. # xxxxxx. Vendor does not accept P-Card purchases. Order placed with "name of company", "salesperson's name" (where possible) and "date of purchase."

   b. If order has been picked up or delivered before you complete the requisition, note that "the item(s) has been picked-up/or has been delivered". Should this not be the case, provide the quoted delivery date.

2. To enter the receipt of the item(s) when delivered and confirmed as complete and accurate.

3. To handle any issues arising from the purchase, for example, quantity discrepancies, expediting of order, invoice discrepancies.

Responsibility of the Purchasing Department:

1. To create the purchase order and issue same to the vendor.

2. To provide the Purchaser and Accounts Payable with copies of the purchase order.

2. Purchase Dollar Value Range from $1,001 up to but **not including** $10,000.

This value range requires a formal, competitive method of acquisition in the form of a Request for Quotation and is centralized in the Purchasing Department.

Requirements:

1. Funds shall be budgeted for.

2. An on line purchase requisition shall be completed by the requisitioner, with appropriate approvals.

3. A formal written specification shall be precisely defined by the requisitioner and approved by the departmental Manager. The approved specification shall be forwarded to the Purchasing Department.

4. Sealed bids shall be solicited by the Purchasing Department in a Request for Quotation (RFQ) to known authorized vendors. A minimum of three (3) competitive bids, where possible, shall be solicited from three (3) separate vendors. All vendors shall receive the same written information.

5. All Request for Quotations shall be issued, opened and awarded by the Purchasing Department.

6. The award shall be based on the lowest compliant bid.

7. The purchase order shall be issued by the Purchasing Department.

3. Purchase Dollar Value Range greater than or equal to $10,000.

This value range requires a formal, competitive method of acquisition in the form of a Request for Tender and is centralized in the Purchasing Department.

Requirements:

1. Funds shall be budgeted for.

2. An on-line purchase requisition shall be completed by the requisitioner, with appropriate approvals.

3. A formal, written specification shall be precisely defined by the requisitioner and approved by the departmental Manager. The approved specification shall be forwarded to the Purchasing Department.

4. Sealed bids shall be solicited by the Purchasing Department by way of a Request for Tender (RFT) to known authorized vendors. A minimum of three (3) competitive bids, where possible, shall be solicited from three (3) separate vendors. All vendors shall receive the same written information.

5. All Request for Tenders shall be issued, opened and awarded by the Purchasing Department.

6. The award shall be based on lowest compliant bid. The purchase order shall be issued by the Purchasing Department.

B. SERVICES (No Purchase of Services Permitted with P-Card)

All Dollar Value Ranges (*Reference Appendix E- Prequalification/Tender Process Flow Chart for Services, Page 74*).

1. Purchase Dollar Value Range >$0 up to and including $1,000.

This method of purchase is non-competitive and, as such, may be sole or single sourced by the Requisitioner and is Purchasing Department centralized.

Requirements:

Reference B.2. Requirements, #1 through #5.

2. Purchase Dollar Value Range > $1,000.

This method of purchase requires competition and is Purchasing Department centralized.

Requirements:

1. A purchase requisition shall be completed by the requisitioner, with required approvals.

2. A "Contractor Risk Assessment Form" (Reference Appendix F-Contractor Risk Assessment Form Page 76) shall be completed by the requisitioner to determine the degree of risk involved with the required service which will determine whether prequalification process is required. If a prequalification is required, the requisitioner and the Manager, Safety & Training, shall define the requirements and create the document.

3. The requirement (specification) shall be defined and documented by the requisitioner, either in the description field of the requisition or on a separate specification document, depending on the length and complexity of the requirement.

4. WSIB Clearance Certificate, Insurance Requirement, Contract Document and Undertaking to Comply Document, shall be requested from the successful company by the Purchasing Department.
5. The purchase order awarded to the successful company shall be issued by the Purchasing Department once requirements #1 through #4 are met in full.

C. GOODS AND SERVICES

Request for Proposal (RFP) – All Purchase Dollar Value Ranges

This method of acquisition is centralized in the Purchasing Department when:

- expertise and experience is required; or
- comprehensive technical specifications cannot be fully defined or specified; or
- alternate methods are being sought to perform a certain function of service.

Requirements:

1. Funds shall be budgeted for.

2. An on-line purchase requisition shall be completed by the requisitioner, with appropriate approvals.

3. For procurement of services only, a "Contractor Risk Assessment Form" (Reference Appendix F-Contractor Risk Assessment Form, Page 76) shall be completed by the requisitioner to determine degree of risk/ whether prequalification is required (Reference Appendix E–Prequalification/ Tender Process Flow Chart for Services, Page 74). If a prequalification is required, the requisitioner and the Manager, Safety & Training, shall define the requirements and create the document.

4. If required, the prequalification precedes the "RFP" and only prequalified vendors/contractors receive the proposal package.

5. The "Terms of Reference" (Reference Section 3.0, Definitions, Page 9) section of the RFP is developed by the requisitioner and the front end of the document (for example, Information to Bidders, Requirements at Time of Closing, Conditions) is prepared by the Purchasing Department.

6. All RFP's shall be issued, advertised, if required, opened and awarded by the Purchasing Department.

7. The Formal RFP shall be issued by the Purchasing Department to known/preferred/prequalified vendors and shall be a sealed bid process.

8. All RFP's shall clearly set out the evaluation criteria and weightings upon which an award of the RFP may be made. The requisitioner shall define the criteria and weightings.

9. All proposals that meet the required terms, conditions and terms of reference outlined in the RFP document shall be evaluated based on the evaluation criteria and weightings.

10. The proposal earning the highest score based on the criteria and weightings shall be receive the award.

11. For services only, Contract Documents and Undertaking to Comply, Liability Insurance and WSIB Clearance Certificates shall be requested by the Purchasing Department.

12. The purchase order shall be issued only after all requirements are met.

13. Exceptions to this policy may include:

    Policy for Emergency Purchasing (Reference Section 5.10, Policy #10, Page 33)
    Policy for Non-Competitive Purchases (Reference Section 5.1, Policy #1, Page 18)

4.3.3 REFERENCE

Section 3.0 -	Definitions
Section 4.1 -	Types and Goals of Procurement Processes
Section 5.1 -	Policy #1 - Non-Competitive Purchases
Section 5.3 -	Policy #3 – Prequalification of Acceptable Bidders
Section 5.4 -	Policy #4 - Specifications
Section 5.5 -	Policy #5 – Proposals
Section 5.11 -	Policy #11 – Recommendation to Purchase (RTP)
Appendix C -	Sample Front End and RFP Document
Appendix E -	Prequalification/Tender Process Flow Chart for Services

5.0 POLICIES

5.1 POLICY #1 – NON-COMPETITIVE PURCHASES

(Sole Source Procurement, Purchase by Negotiation)

5.1.1 POLICY

The purpose of this policy is to set out guidelines for acquiring goods and/or services without a competitive bidding process. Purchase by negotiation may be adopted, if in the judgment of the Manager, Purchasing and Stores, in consultation with the requisitioning Department Manager, any of the following conditions apply:

- When an unforeseeable condition of urgency exists, and the goods or services cannot be obtained in time through a competitive process.
- When the required item is covered by an exclusive right such as a patent, copyright or exclusive license.
- When the purchase involves a component or replacement part for which there is no substitute.
- When the purchase involves an item for which compatibility with an existing product is an overriding consideration or to avoid violating warranty/guarantee requirements when service is required.
- When the purchase is already covered by a lease-purchase agreement where payments are partially or totally credited to the purchase.
- When no bids were received in a competitive process.
- When only one bid is received in a tender, proposal or quotation call.
- Where two or more identical low bids have been received.
- When the required item is in short supply due to market conditions.
- When the lowest tender, proposal or quotation meeting specifications, terms and conditions substantially exceeds (by at least 20%) the estimated cost and it is **impractical** to recall the tender, proposal or quotation.

- When competitive sourcing for low value procurement would be uneconomical or would not attract bids.

When a Manager intends to select a supplier to provide goods and/or services pursuant to section 5.1.1, the Purchasing Department shall be advised in writing of the compelling rationale that warrants a non-competitive selection for approval prior to entering into any discussions with the supplier.

The supplier, with whom the Manager and the Purchasing Department have the greatest confidence to fulfill the requirement and provides for fair market value, shall be selected.

The contract resulting from negotiations shall be awarded by the Purchasing Department, provided that the funds are available in appropriate accounts within approved budgets including authorized revisions to meet the proposed expenditure.

Any purchase contract for **$100,000** or more in value, excluding taxes and freight, shall require the approval from the President to proceed with negotiations. Further, any negotiated purchase contract for **$100,000** or more in value, excluding taxes and freight, shall again be subject to approval from the President prior to award of contract.

5.1.2 REFERENCE

Section 3.0 - Definitions
Appendix B – Non-Competitive Purchases Form (Policy #1)
Appendix I – Emergency Reporting Form (Policy #10)

5.2 POLICY #2 – ADMINISTRATIVE FEE

5.2.1 POLICY

The purpose of this policy is to outline specific administration fees for bid documents.

Thunder Bay Hydro may charge a minimum administration fee of $25.00 for tender and proposal documents. The Manager, Purchasing & Stores, in conjunction with the Requisitioner, will determine whether a fee will be charged for the document and if so, the amount of the fee.

Cheques shall be made payable to Thunder Bay Hydro. Failure to submit the fee with the tender/proposal/quotation submission may result in disqualification of bid.

5.2.2 REFERENCE

5.3 POLICY #3 – PREQUALIFICATION OF ACCEPTABLE BIDDERS

5.3.1 POLICY

The purpose of this policy is to set out guidelines for the prequalification of acceptable bidders prior to the competitive bid process.

The purpose of the prequalification is to minimize the amount of risk associated with hiring contractors. Further, the process ensures that each bidder can demonstrate the ability to provide the necessary experience, expertise and resources to satisfactorily complete the work required as specified by Thunder Bay Hydro.

It is the responsibility of the Hiring Supervisor (Requisitioner) to assess the potential risk associated with the work by completing the "Contractor Risk Assessment Form" (CRA) (Reference Appendix F-Contractor Risk Assessment Form, Page 76).

1. If the work is determined to be **"high risk"**, a prequalification is required.

2. If the work is determined to be **"medium risk"**, it is at the discretion of the Hiring Supervisor as to whether a prequalification is required. If determined that a prequalification is not required, the risk assessment is subject to review and approval by the Vice President of the hiring Division.

3. If the work is determined to be **"low risk"**, prequalification is most likely not required, however, it is at the discretion of the Hiring Supervisor. If determined that a prequalification is not required, the risk assessment is subject to review and approval by the Vice President of the hiring Division.

The prequalification, if determined to be required, is developed by the Hiring Supervisor in conjunction with the Manager, Safety & Training.

5.3.2 CRITERIA

This may include but not be limited to the following:

1. Experience on similar work (both from a company and staff perspective)

2. References provided from other customers for similar work

3. Verification of applicable certificates, licenses, membership

4. Health and safety policies and programs

5. WSIB and insurance requirements

6. Financial capability

To determine whether a company prequalifies, the Hiring Supervisor will be responsible for evaluating the work experience, qualifications, references, and vehicles and equipment portion of

the prequalification, while the Manager, Safety & Training will focus on safety requirements, qualifications and training, insurance, and WSIB requirements.

The recommendation regarding acceptable companies who will be invited to participate in the subsequent competitive sealed bid will be forwarded to the Purchasing Department by the hiring Supervisor. Only these prequalified companies will be invited to submit sealed tenders/proposals.

5.3.3 REFERENCE

Appendix D – Contractor Safety Management Program
Appendix E – Prequalification/Tender Process Flow Chart for Services
Appendix F - Contractor Risk Assessment Form
Appendix G – Instruction to Assist the Hiring Supervisor
Hiring Supervisor Instruction to Purchasing Department Form
Prequalification Review – Manager, Safety & Training
Prequalification Review – Hiring Supervisor
Appendix H – Sample Prequalification Document

5.4 POLICY #4 – SPECIFICATIONS

(for the issuance of “Request for Quotation” (RFQ) and “Request for Tender” (RFT)

5.4.1 POLICY

The purpose of this policy is to provide guidelines with respect to specifications.

When the requirement to be purchased can be fully defined and the award can be achieved on the basis of low bid to specification, a “Request for Quotation” (RFQ) or “Request for Tender” (RFT) shall be issued by the Purchasing Department. The Purchasing Department shall process the specification in the format required dependent on the dollar value of the purchase (RFQ, RFT).

Where it is not possible to prepare precise specifications in order to issue a Request for Tender for the provision of goods and/or services, a Request for Proposals shall be issued.

1. The Department whose budget provides for the acquisition of goods and/or services shall be responsible to prepare and provide specifications. Specifications shall be approved by the requisitioning Department Manager and then forwarded to the Purchasing Department with approval attached.

   - Specifications should be detailed but, where possible, not brand specific to allow for potential vendors to provide alternatives in the event an equal or better-proven product or method is available and shall not deter a competitive process.

   - Potential vendors shall not be requested to expend time, money or effort on design or in developing specifications or otherwise help define a requirement beyond the normal level of service expected from vendors. When such services are required:

     - The Manager, Purchasing & Stores shall be advised.

     - The contracted vendor will be considered as a Consultant and unable to make an offer for the supply of the goods and services, unless approved by the Vice President of the Division and the Manager, Purchasing & Stores.

     - A fee shall be paid to the contracted vendor.

     - The detailed specification shall be approved by the Manager of the Requisitioning Department and shall become the property of Thunder Bay Hydro for use in obtaining competitive bids.

2. The Purchasing Department shall review and recommend changes to the specifications when deemed necessary and resulting changes to specifications shall be made with the cooperation of the Requisitioning Department. The Manager, Purchasing & Stores, shall assist in determining if the specifications are

clear in understanding, in the appropriate form, commercially practical and in sufficient generic form, where possible, to ensure competitive bidding.

The Manager, Purchasing and Stores may reject any specification not consistent with the Purchasing Policy.

3. In cases where the specification will result in a sole or single source purchase, it shall be required that the Hiring Supervisor complete the "Non-Competitive Purchases Form" (Reference Appendix B-Non-Competitive Purchases Form (Policy #1), Page 52) and authorization shall be required by the Requisitioner's Vice President. The completed form shall be forwarded to the Purchasing Department where the information will be utilized to complete a Recommendation to Purchase (RTP). The RTP shall require approval from the Manager, Purchasing & Stores, Vice President, Finance as required by the Manager, Purchasing & Stores and the President, if deemed required by the Vice President, Finance.

4. The Purchasing Department shall process the specification as a "Request for Quotation" (RFQ), either formal or informal or a "Request for Tender" (RFT), dependent on the dollar value of the purchase.

5.4.2 REFERENCE

Section 4.1	- Types and Goals of Procurement Processes
Section 4.2	- Circumstances For Use of Procurement Processes
Section 5.5	- Policy #5 – Proposals
Section 5.11	- Policy #11 – Recommendation to Purchase
Appendix B	- Non-Competitive Purchases Form (Policy #1)
Appendix C	- Sample Front End and RFP/RFT Document
Appendix J	- Purchasing Guidelines Regarding Bid Irregularities
Appendix Q	- Purchasing 101
Appendix R	- Before Entering a Purchase Requisition
	- How to Create and Complete a Requisition

5.5 POLICY #5 – PROPOSALS

5.5.1 POLICY

The purpose of this policy is to provide guidelines with respect to Request for Proposals.

The Request for Proposal (RFP) is a competitive method of purchase that may be tendered by way of public call or invitational bid. This method of purchase is utilized when the requirements for goods or services needed cannot be definitively specified and the suitability of the purchase of goods and services depends upon the expertise and experience of the successful vendor, examples include:

1. Professional services (architects, legal counsel, engineers).
2. Consulting services (computer systems, insurance).
3. Goods and services which the Requisitioner cannot (or should not) strictly or easily define without more information from the vendor(s) (insurance).
4. Occasions when innovative solutions are sought.

5.5.2 ROLES AND RESPONSIBILITIES

The **Requisitioning Department** shall provide the Purchasing Department with:

1. A purchase requisition, with approvals as required.

2. For procurement of services only, a "Contractor Risk Assessment Form" (Reference Appendix F-Contractor Risk Assessment Form, Page 76) shall be completed by the requisitioner to determine degree of risk/ whether prequalification is required (Reference Appendix E–Prequalification/ Tender Process Flow Chart for Services, Page 74). If a prequalification is required, the requisitioner and the Manager, Safety & Training, shall define the requirements and create the document.

3. If required, the prequalification precedes the "RFP" and only prequalified vendors/contractors receive the proposal package.

4. The terms of reference (Section 3.0, Definitions, Page 9)

5. The evaluation criteria and weightings to be applied in assessing the proposals submitted.

6. A summary of the proposals received noting analysis of each submission.

7. A recommendation regarding the successful proposal. The award is to be made to the vendor meeting all mandatory requirements and determined by reference to the evaluation criteria and weightings providing best value.

The **Purchasing Department** shall be responsible for:

1. Making itself available to the Requisitioner for consultation during the creation of the RFP.

2. Issuing the RFP.

3. Participating as a member of the Proposal Selection/Review Committee, when required.

4. Awarding the RFP, administering all necessary contract documents provided that:

    a. Sufficient funds are available and approved by the Finance Division,
    b. The award is made to the Supplier meeting all mandatory requirements and providing best value as stipulated in the Request for Proposal,
    c. The Purchasing Department is in receipt of a funded requisition, and
    d. The provisions of this Policy are followed.

5.5.3 SELECTION COMMITTEE

A Selection Committee comprised of a minimum of two representatives from the Requisitioning Department, and when the contract price is anticipated to be $100,000 or greater, a representative from the Purchasing Department shall review all proposals against the established criteria, reach consensus on the final rating results, and ensure that the final rating results, with supporting documents, are kept in the procurement file.

5.5.4 COMMUNICATION WITH PROPONENTS

During the proposal process all communication with bidders shall be through the Purchasing Department.

5.5.5 REFERENCE

Section 3.0 – Definitions
Section 4.1 - Types and Goals of Procurement Processes
Section 4.2 - Circumstances for Use of Procurement Processes
Section 5.11 – Policy #11 – Recommendation to Purchase
Appendix C – Sample Front End and RFP/RFT Document
Appendix J – Purchasing Guidelines Regarding Bid Irregularities
Appendix Q – Purchasing 101
Appendix R - Before Entering a Purchase Requisition
- How to Create and Complete a Requisition

5.6 POLICY #6 – FINANCIAL SECURITY REQUIREMENTS

The purpose of this policy is to set out guidelines for financial security requirements for tenders and proposals.

5.6.1 BID DEPOSIT

A Bid may be required to be accompanied by a form of Bid deposit to guarantee entry into a Contract, as follows:

ESTIMATED TOTAL ACQUISITION COST	MINIMUM DEPOSIT REQUIRED
$50,000 OR LESS (WHERE THE SCOPE OF WORK OR SPECIAL PROJECTS ARE DEEMED TO REQUIRE A BID DEPOSIT)	
ER THAN $50,000	

The amount of the bid deposit shall be determined by the Manager of the Requisitioning Department, in conjunction with the Manager, Purchasing & Stores.

A bid deposit shall be provided in Canadian currency and in one of the following formats:

1. A bid bond or an agreement to bond issued by a bonding agency currently licensed to operate in the Province of Ontario naming Thunder Bay Hydro as the Oblige.

2. A certified cheque made payable to Thunder Bay Hydro.

3. An irrevocable letter of credit naming Thunder Bay Hydro as the beneficiary.

4. A money order made payable to Thunder Bay Hydro.

Thunder Bay Hydro does not pay interest on any bid deposits.

All bid deposits must be original documentation, signed and sealed as appropriate. No faxed or photocopies will be accepted.

Thunder Bay Hydro is authorized to cash and deposit any bid deposit in Thunder Bay Hydro's possession that is forfeited as a result of non-compliance with any of the terms, conditions and/or specifications of a sealed bid.

Bid deposits shall be dated for a minimum of 60 days, or the same period/term as specified in the proposal or tender. All bid deposits except those of the proponents submitting the two lowest acceptable bids shall be returned no later than five (5) working days following the opening of bids by Thunder Bay Hydro. The bid deposit of the bidder submitting the second lowest acceptable tender or the second highest evaluated proposal will be held until not later than ten (10) business days after the execution of the contract by Thunder Bay Hydro.

If, within 60 days (the period of the contract) after the date of opening bids, a bidder has not been notified that its bid has been recommended to Thunder Bay Hydro for acceptance, its bid deposit will be returned on demand. Such demand for the return of a bid deposit or the return of the bid deposit by Thunder Bay Hydro to a bidder whose bid has not been accepted shall constitute the withdrawal or expiry of the validity of the bid.

5.6.2 BONDING REQUIREMENTS

Performance, Labour and Material and/or Maintenance Bonds are required for all construction projects exceeding $100,000 for a minimum of 50% of the bid amount. For construction projects less than $100,000, the bid amount will be determined at the discretion of the Manager, Purchasing & Stores in conjunction with the Requisitioner.

All bonds must be originals, signed and sealed. No faxed or photocopies will be accepted.

5.6.3 INSURANCE REQUIREMENTS

The standard per occurrence***** insurance minimums are as follows:

$5 Million – Commercial General Liability Policy
$5 Million – Automobile Liability Policy
$5 Million – Professional Errors and Omissions Liability.

***** The per occurrence coverage can be entirely primary insurance, or a combination of primary and umbrella, as long as it totals $5,000,000 “per occurrence”.

Bid documents must clearly indicate the insurance requirements to be provided and maintained until the termination of the contract by the successful bidder, including:

A “Cross Liability” clause.

Endorsement certifying that Thunder Bay Hydro is named as an additional insured.

An endorsement to the effect that the policy or policies will not be altered, cancelled or allowed to lapse without thirty (30) days prior written notice to Thunder Bay Hydro.

5.6.4 WORKPLACE REQUIREMENTS

Workplace Safety & Insurance Board (WSIB) Requirements:

1. The successful bidder shall furnish a WSIB Clearance Certificate indicating their WSIB firm number, account number and that their account is in good standing. The form must be provided prior to the formal award of contract. The successful bidder further agrees to maintain their WSIB account in good standing throughout the contract period.

2. Thunder Bay Hydro will require the successful bidder to produce a Clearance Certificate from WSIB from time to time during the contract on request and/or prior to final payment.

1. If the successful bidder is a self-employed individual, partner or executive officer who does not pay WSIB premiums and is recognized by WSIB as an "independent operator", a letter from WSIB acknowledging independent contractor status and confirming that WSIB coverage is not required, must be provided to Thunder Bay Hydro prior to formal award of contract.

5.6.5 REFERENCE

5.7 POLICY #7 – EXERCISE OF CONTRACT RENEWAL OPTION

5.7.1 POLICY

The purpose of this policy is to set out guidelines regarding exercising an option to renew with an existing contract.

Where a contract contains an option for renewal, the Manager of the department which requisitioned the requirement, may authorize the Purchasing Department to exercise such option provided that:

- the supplier's performance in supplying the goods and/or services is considered to have met the requirements of the contract, and
- the Manager of the Requisitioning Department and the Purchasing Department agree that the exercise of the option is in the best interest of Thunder Bay Hydro, and
- funds are available in appropriate accounts within approved budgets including authorized revisions to meet the proposed expenditure.

The authorization from the Manager of the requisitioning Department shall include a written explanation as to why the renewal is in the best interest of Thunder Bay Hydro and include comment on the market situation and trend.

5.7.2 REFERENCE

5.8 POLICY #8 - CONTRACT AMENDMENTS AND REVISIONS

The purpose of this policy is to set out guidelines regarding contract amendments and revisions to an existing contract.

No amendment or revision to a contract shall be made unless the amendment is in the best interest of Thunder Bay Hydro. This decision is to be made by the Manager of the requisitioning Department in conjunction with the Purchasing Department.

No amendment that changes the price of a contract shall be agreed to without a corresponding change in the requirement or scope of work.

Amendments to contracts are subject to the identification and availability of sufficient funds in appropriate accounts within approved budgets including authorized revisions.

5.8.1 REFERENCE

5.9 POLICY #9 – LOCAL SUPPLIERS

5.9.1 POLICY

The Province of Ontario's *Discriminatory Business Practices Act (R.S.O. 1990)* has been established to prevent discrimination in Ontario on the ground of race, creed, colour, nationality, ancestry, place of origin, sex, or geographical locations of persons employed or engaging in business. Granting preference, therefore, to local suppliers to supply goods and/or services to Thunder Bay Hydro cannot be undertaken.

5.9.2 REFERENCE

5.10 POLICY #10 – EMERGENCY PURCHASING

5.10.1 POLICY

The purpose of this policy is to set out guidelines for acquiring goods and/or services when an emergency arises.

When the President has declared an emergency, goods and/or services shall be acquired by the most expedient and economical means. The Purchasing Department will provide cooperative assistance when requested to expedite any purchasing documents necessary to deal with the emergency. Any purchase acquisition document issued under such conditions shall be justified and approved by the Vice President of the initiating department. For amounts exceeding $50,000, the Vice President shall issue an information report to the President.

Subsequent to the resolution of the Emergency, all transactions require an online requisition to be entered to complete the procurement process. The initiating department shall complete the Emergency Reporting Form and forward it to the Manager, Purchasing & Stores.

5.10.2 REFERENCE

Section 3.0 – Definitions
Appendix B – Non-Competitive Purchases Form (Policy #1)
Appendix I – Emergency Reporting Form (Policy #10)

5.11 POLICY #11 – RECOMMENDATION TO PURCHASE (RTP)

5.11.1 POLICY

The purpose of this policy is to outline the circumstances when a "Recommendation to Purchase" (RTP) is required.

A "Recommendation to Purchase" is required (prior to award) when at least one (1) of the following circumstances exists:

1. The Requisitioner is recommending to the Purchasing Department a vendor which is not low price to specification (i.e. a recommendation may be based on delivery);

2. The good or service has not been budgeted for;

3. The cost of the tendered good or service exceeds the budgeted amount by more than 20%;

4. Only one bid has been received in the tendering process;

5. The item or service has been sole sourced or single sourced.

A "Recommendation to Purchase" shall be issued by the Purchasing Department and requires the approval of the following:

1. Manager, Purchasing & Stores, for all RTP's

2. Vice President, Finance, at the discretion of the Manager, Purchasing & Stores

3. President, at the discretion of the Vice President, Finance

Information required from the Requisitioner for the Recommendation to Purchase, includes but may not be limited to:

1. Justification for recommendation.

2. Budgeted amount .

3. In such cases where the specification will result in a sole or single source purchase, it shall be required that the Hiring Supervisor complete the "Non-Competitive Purchases Form" (Reference Appendix B-Non-Competitive Purchases Form (Policy #1) Page 52) and authorization shall be required by the Requisitioner's Vice President.

5.11.2 REFERENCE

Section 5.1 - Non-Competitive Purchases

5.12 POLICY #12 – BID IRREGULARITIES

5.12.1 POLICY

The purpose of this policy is to define the various irregularities with regards to bid submissions.

A bid irregularity is a deviation between the requirements (terms, conditions, specifications special instructions) of a bid request and the information provided in a bid response.

For the purpose of this policy, bid irregularities are further classified as "major irregularities" or "minor irregularities".

- A **"major irregularity"** is a deviation from the bid request that affects the price, quality, quantity or delivery, and is material to the award. This also includes late bids, bid surety not in the form specified; amount of the surety must be equal or greater than the amount requested, attendance at mandatory site visits. If the deviation is permitted, the bidder could gain an unfair advantage over competitors. The Manager, Purchasing & Stores, shall reject any bid which contains a major irregularity.

- A **"minor irregularity"** is a deviation from the bid request, which affects form, rather than substance. The effect on the price, quality, quantity or delivery is not material to the award. If the deviation is permitted or corrected, the bidder would not gain an unfair advantage over competitors. The Manager, Purchasing & Stores, may permit the bidder to correct a minor irregularity.

Regarding mathematical errors, such as errors found in taxes, extensions, additions, etc. the unit price shall generally govern.

5.12.2 ACTION TAKEN

The Manager, Purchasing & Stores shall be responsible for all action taken in dealing with bid irregularities and acts in accordance with the nature of the irregularity:

1. Major irregularity (automatic rejection)

2. Minor irregularity (bidder may rectify)

5.12.3 REFERENCE

Appendix J - Purchasing Guidelines Regarding Bid Irregularities

5.13 POLICY #13 – CONSULTING AND PROFESSIONAL SERVICES

5.13.1 POLICY

The purpose of this policy is to set out guidelines for acquiring Consulting and Professional Services as defined in Section 3.0, Definitions, Page 6, and in accordance with Thunder Bay Hydro Purchasing Policies. Where possible, all qualified firms providing Consulting and Professional Services shall have fair access to Thunder Bay Hydro assignments.

A consultant or professional may be required for various reasons. Some examples include:

a. To supplement staff time, particularly appropriate when the project is a non-recurring one.

b. To supplement staff expertise when tasks may call for special skills that current staff does not posses or cannot be learned quickly or easily by staff.

c. To ensure objectivity when projects which may be controversial or political and a consultant may be able to find a “win-win” solution.

d. To obtain a variety of skills from a consulting firm with access to a number of people with different skills.

e. To assist in handling work load or projects.

5.13.2 SELECTION TYPES(1 to 4 as noted below)

1. Selection Based on Responses to a “Request for Proposal” (RFP):

This process requires that a consultant submit a full project proposal in order to be considered (Reference Section 5.5, Policy #5-Proposals, Page 25).

The steps in the RFP – Consultant process typically includes:

- Distribution of RFP package (by Purchasing Department)
- Review of proposals (by requisitioning Department)
- Preliminary ranking (by requisitioning Department) identifies candidates for interviews
- Interview (optional) (by requisitioning Department)
- Recommendation of Selection (by requisitioning Department).

2. Combining the RFP in a Two-Part Selection Process:

This process may be used to broaden the pool of consultants. RFP's shall be made available to any consulting firm that might reasonably be interested in the project. Interviews may be conducted at any one of the two stages of the process.

Part One:
This selection process follows an RFP process to identify a "short list" of consultants to be invited to submit full project proposals. Interested consulting firms shall submit a statement of qualifications corresponding to the required scope and description of work as defined by the requisitioning Department.

The requisitioning Department shall review the statements of qualifications submitted and prepare a "short list" of only those firms that meet the full required qualifications.

Part Two:
RFP's shall be issued by the Purchasing Department to those consulting firms which have been short listed.

3. Sole-Source Procurement:

This approach may be considered when selecting a single consultant either for a particular task or for a continuing relationship. For both legal and political reasons, the Requisitioning Supervisor considering the use of this selection process shall provide the reason for doing so, in writing, to the Purchasing Department prior to making any commitment with the consultant.

Flexibility to use this selection process may be appropriate under the following circumstances:

- When a consultant, due to prior work with Thunder Bay Hydro, has significant background in a matter requiring resolution in a short period of time.
- When it is practically necessary to retain a local consultant and there is only one who is qualified.
- When Thunder Bay Hydro requires the services of a consultant with a unique specialty.
- If there is not sufficient time to go through a formal search procedure.
- When significant cost savings can be achieved by using a consultant who is familiar with Thunder Bay Hydro and its procedures.

4. Alternate Form of Single-Source Procurement:

Should a consultant be familiar with a project from work done under a previous contract **that was awarded after a competitive process**, consideration may be given to use an amendment to that contract. Consideration to use an amendment to the contract to retain the consultant's services for later stages of the project or a related project shall be

approved by the Purchasing Department prior to any commitment being made to a consultant.

5.13.3 TYPE OF CONTRACT

Fixed price (also called lump sum) whereby a fixed price is received for a defined scope of services. This type of contract may include additional, extra-cost options.

Time and expense (cost-plus), whereby a consultant is reimbursed on a fixed formula for professional time and expenses. This type of contract shall be utilized to provide maximum flexibility where the scope of services is impossible to determine in advance.

5.13.4 REFERENCE

Section 3.0 - Definitions

5.14 POLICY #14 – COOPERATIVE PURCHASING

5.14.1 POLICY

Thunder Bay Hydro may participate with other government agencies, public authorities or businesses, in cooperative acquisition ventures when it is in the best interest of Thunder Bay Hydro to do so.

The policies and procedures of Thunder Bay Hydro will be followed, such as requirements regarding Contractor Risk Assessment, prequalification, WSIB and insurance.

Each agency will issue its own contract and is responsible for the remainder of the procurement function (issuing the purchase order, receiving, inspecting and payment).

5.14.2 REFERENCE

5.15 POLICY #15 – DISPOSAL OF SURPLUS GOODS POLICY

5.15.1 POLICY

The purpose of this policy is to set out guidelines for the disposal of surplus goods which shall be evaluated on a case by case basis.

5.15.2 METHOD OF DISPOSAL

1. The Manager, Purchasing & Stores, shall have the authority to sell, exchange, or otherwise dispose of goods declared as surplus to the needs of Thunder Bay Hydro, and where it is cost effective and in the best interest of Thunder Bay Hydro to do so, items or groups of items may:

2. Be transferred to other departments within Thunder Bay Hydro; or

3. Be offered for sale by external advertisement or in-house (where it is deemed appropriate, a reserve price may be established); or

4. Be sold or traded to the original supplier or others in that line of business where it is determined that a higher net return will be obtained than following other procedures; or

5. Be donated to a non-profit agency; or

6. Be recycled; or

7. In the event that all efforts to dispose of Goods by sale are unsuccessful, these items may be scrapped.

8. The Manager, Purchasing & Stores, shall submit an annual report to the Vice President, Finance, summarizing the disposal of all surplus Goods pursuant to this policy.

5.15.3 REFERENCE

Appendix K – Surplus/Scrap – Identification and Disposal Form
Appendix L – Surplus/Scrap Vehicle – Identification and Disposal Form

5.16 POLICY #16 – PURCHASING CARD POLICY AND PROCEDURES

5.16.1 INTRODUCTION

Purpose and Scope

To outline the policy and procedures for the use and control of Thunder Bay Hydro's Purchasing Card.

Background

Departmentally approved employees are authorized to use the Purchasing Card to efficiently purchase low-dollar-value goods and services in support of sound business practices. In addition, benefits will accrue in Finance by reducing the number of invoices processed, resulting in fewer cheques being prepared in Purchasing, by reducing the number of purchase requisitions resulting in fewer low dollar purchase orders and for user departments by providing a simplified process and an increased level of service.

Authority

The Administrator (Vice President, Finance and/or designate(s)) authorizes Supervisors to empower approved employees within their Departments or areas of responsibility.

Inquiries

Inquiries related to the accounting aspects of this policy should be addressed to the Administrator.

Inquiries related to the purchasing aspects of this policy should be addressed to the Manager, Purchasing and Stores.

5.16.2 POLICY

The Administrator is responsible for the Purchasing Card co-ordination function within Thunder Bay Hydro.

Each Purchasing Card will have a unique number, and will be issued in the name of Thunder Bay Hydro and the name of the employee who has been authorized to use that card. The card is not transferable to any other employee, even if that other employee is also authorized to use a Purchasing Card on behalf of Thunder Bay Hydro.

Supervisors have been delegated purchasing and approval signing authority for low-dollar-value purchases.

The Purchasing Card will be issued to employees approved by Supervisors who occupy positions with delegated low-dollar-value purchasing authority.

The credit limit, which is the maximum amount chargeable to each Purchasing Card, is restricted to the maximum dollar limit established by each respective Vice President or Vice President, Finance, based on the forecasted monthly use of the Purchasing Card.

The Purchasing Cards must not be used:

- When the purchase of a service requires specific performance(s) of the supplier of such service (i.e., completion dates, certifications, warranties, shipping costs, etc.).

- When the purchase of a service involves contracted labour and WSIB clearance certificates, contract documents, insurance, etc. are required to be on file.

- When the goods and services are available under an existing blanket purchase order or contract.

- When the goods are available from Stores.

- When the cost of the goods or services would be significantly increased as a result of using the card and an alternative method of payment is available (i.e., a discount is provided by the vendor as a result of not using the card).

- For purchasing goods and services which have Thunder Bay Hydro standardization (i.e. Thunder Bay Hydro furnishings).

- For personal purchases.

- To obtain cash advances.

No cardholder may accept cash or a cheque from a vendor who is making a refund pertaining to a transaction previously charged to a Purchasing Card account. The vendor in all cases must issue a credit voucher.

Every cardholder shall be informed in writing of his or her responsibilities and restrictions regarding the use of the Purchasing Card and shall agree to them in writing (Reference Appendix N-Purchasing Card-Purchasing Acknowledgement of Responsibilities and Obligations, Page 95). Cardholders will be held liable for any misuse or wilful disregard of policies or operating procedures which result in a loss of money, fraud or collusion and may be subject to discipline up to and including termination for such infractions.

To avoid the payment of interest, payments to the bank shall be made <u>within 21 days following the monthly statement date</u> (refer to Payment of Monthly Statements, and Payment and Calculation of Interest sections – Page 49).

The liability for authorized charges on the Purchasing Card rests with Thunder Bay Hydro, not the individual cardholder.

The maximum Thunder Bay Hydro liability for unauthorized use of the card following loss or theft of the card shall be $50. Unauthorized use means a use that did not benefit Thunder Bay Hydro and was made by someone other than the cardholder. Thunder Bay Hydro is not liable for any unauthorized use of the card which occurs after notification of loss, theft, or cancellation has been received by the bank. However, if the loss or theft or a card is not reported immediately, Thunder Bay Hydro may be liable for all unauthorized purchases charged to the account.

There is a fee of $20 per Purchasing Card per year.

Purchases made outside Canada will be converted to Canadian funds at a rate established by USBank™ Canada.

5.16.3 RESPONSIBILITIES

The Cardholder is responsible for:

- Adhering to all conditions and restrictions imposed on the Purchasing Card by Thunder Bay Hydro and the bank.

- Submitting the "Employee Acknowledgement of Responsibilities and Obligations" form to the Purchasing Manager (Reference Appendix N, Page 95).

- Ensuring that the Purchasing Card, monthly statements and other documents bearing the card number are kept in a secure location with controlled access.

- Immediately notifying the bank, the Respective Vice President and the Administrator of any loss or theft of the card.

- Informing the Administrator of cancellation, changes in business address or area of responsibility, and/or telephone number, through the respective Vice President.

- Returning the card to the Administrator for cancellation, as appropriate, through the Respective Vice President.

- Maintaining a "Purchasing Card Purchases Record' (Reference Appendix "O", Page 97), on a monthly basis, for all purchases made with the Purchasing Card.

- Resolving disputed charges with the assistance of the Administrator, as required.

- Forwarding all supporting documentation (i.e., cash register and Purchasing Card receipts, vendor notices, Purchasing Card Purchases Record, etc.) related to all purchases made with the Purchasing Card to Finance for reconciliation, account verification and audit purposes.

- Obtaining the required MSDS's for all WHMIS controlled products purchased with the Purchasing Card and immediately forwarding a copy to the Safety and Training Division.

- Reporting all items purchased with the Purchasing Card that form part of Asset Inventory.

- Ensuring that all vendors performing service work have the required comprehensive liability insurance, Workers' Compensation coverage and comply with the Health and Safety and Training requirements.

The Vice Presidents are responsible for:

- Assessing the need for Purchasing Cards based on operational requirements.

- Identifying the employee(s) who will be authorized to make low-dollar-value purchases through the use of a Purchasing Card.

- Establishing the credit limits, transaction limit and monthly limit for each cardholder

- Specifying the types of items to be purchased with the card, as need be.

- Preparing and submitting the appropriate bank forms and other pertinent information to the Administrator for the issuance or cancellation of cards, increases or decreases to credit limits, change of address or change in Division or area of responsibility (Reference "Cancellation of Purchasing Cards", Page 46).

- Ensuring that each cardholder is informed of his or her responsibilities regarding the use of the Purchasing Card.

- Ensuring that the use of Purchasing Cards conforms to Divisional and corporate policy and procedures.

- Monitoring and controlling the utilization of Purchasing Cards within their Division or area of responsibility.

- Reviewing and approving, on a monthly basis, the Purchasing Card Purchases Records for all purchases charged to their budgets. In the absence of a Vice President, the Vice President can delegate this responsibility to a supervisor.

The Administrator is responsible for:

- Assigning the Purchasing Card payment function within the finance area;

- Assisting the cardholders to resolve disputed charges, as required (refer to Disputed Charges – page 49).

- Authorizing the issuance or withdrawal of Purchasing Cards with the bank.

- Processing increases or decreases to credit limits, as requested by the Vice Presidents.

- Processing bank forms with respect to changes of address and changes of Division or area of responsibility, as requested by Supervisors.

- Developing corporate policies and procedures on low-dollar-value purchasing for goods and services.

- Ensuring that the conduct of all purchasing activity is done in accordance with approved Purchasing policies and procedures.

- Compiling and reporting pertinent Purchasing Card data to the Supervisors, as required.

- Providing co-ordination with respect to monitoring the overall utilization of Purchasing Cards within Thunder Bay Hydro.

5.16.4 PROCEDURES

Requests for Purchasing Cards

The "Employee Information section of the application form must be completed and signed by the employee and approved by the respective Vice President for each card requested (Reference Appendix M-Purchasing Card Application Form, Page 94). Personal credit information is not required, as the card will be issued to Thunder Bay Hydro. The lower part of the form entitled "Unit Information" and "Company Authorization" will be completed by the Administrator.

The approved application form must be sent by the respective Vice President to the Administrator for transmittal to the bank.

Purchasing Cards are expected to be issued within five (5) working days from the date that the application form is received by the bank. The cards will be sent directly to the Administrator at the address indicated on the Bank Application Form.

Issuance of Purchasing Cards

Upon receipt of the cards from the bank, the Administrator must review the listing of enclosed cards for accuracy. Any inaccuracies are to be reported immediately to the bank by the Administrator.

The respective Vice President must inform the cardholder of the responsibilities and restrictions regarding the use of the Purchasing Card and obtain a written Employee "Acknowledgement of Responsibilities and Obligations" form (Reference Appendix N, Page 95) from each cardholder before issuing the card. The Acknowledgement of Responsibilities and Obligations form shall be forwarded to the Administrator for safekeeping.

The cardholder must sign the Purchasing Card and store it in a secure place until used.

Cancellation of Purchasing Cards

The cardholder must complete a "Purchasing Card Request for Change" form (Reference Appendix P, Page 98) and return the card cut in half to the Administrator for cancellation, through the respective Vice President, when:

- specifically requested to return the card by the Administrator or the respective Vice President
- upon transfer to another Department or area of responsibility or
- upon termination of employment with Thunder Bay Hydro.

Lost or Stolen Purchasing Cards

The cardholder must immediately notify the bank of any loss or theft of the card through the Hotline service at 1-800-588-8065. Lost or stolen cards can be reported 24 hours a day. The cardholder must also advise their respective Vice President who shall confirm the loss or theft in writing by forwarding a change form to the Administrator. If the card is stolen, the police must be notified and a police report requested by the respective Vice President.

If the lost or stolen card should eventually be recovered or found, it must be cut in half and returned to the Administrator through the Respective Vice President.

Change of Address or Change of Division or Area of Responsibility

To change the billing address or the Division, the respective Vice President must complete the "Purchasing Card Request for Change" form (Reference Appendix P, Page 98) and forward it to the Administrator.

The change of address is expected to be made within three (3) working days from the date that the form is received by the bank.

With respect to a change of Division or area of responsibility, the reason for cancellation of the card must be indicated under "Reason" on the "Purchasing Card Request for Change" form (Reference Appendix P, Page 98). The card will be cancelled when the form is received by the bank. If another card is required for low-dollar-value purchases related to the new Division or area of responsibility, a new Purchasing Card Application form must be completed by the respective Vice President and sent to the Administrator (Reference "Requests for Purchasing Cards", Page 45.

Modification of Credit Limit

To modify a credit limit, the respective Vice President must complete the "Purchasing Card Request for Change" form – Change of Credit Limit (Reference Appendix P, Page 98) and forward it to the Administrator.

The change to the credit limit is expected to be made within three (3) working days from the date that the form is received by the bank.

Disputed Charges

Items charged on monthly statements of accounts that do not accurately reflect the transactions made by the cardholder (i.e., bank errors such as wrong amount, incorrect account number, multiple postings of the same item, etc.) are considered to be disputed items.

The cardholder must notify the Administrator immediately by telephone when disputed items as stated under Disputed Charges section are involved, as well as inform the respective Vice President concerned. Disputed items reported by cardholders will be credited on the individual statement the following month (provided they are legitimate). The amount indicated on the statement is the amount that should be paid to the bank.

The cardholder shall provide information and assistance to the bank to settle the disputed items, as required.

If the questionable item is not a bank error (i.e., late delivery, defective goods, wrong price, quantity difference, returned goods, etc.), the matter must be settled directly with the vendor by the cardholder. Such matters must be drawn to the vendor's attention immediately so as to minimize the delay in obtaining a credit to the Purchasing Card account. When the amount in dispute is of an insignificant dollar value, notices to vendors should be confirmed in writing even though settlement may be accomplished through telephone calls. Copies of the notices to vendors should be attached to the monthly Purchasing Card Purchases Record. Disputes with vendors are not considered to be disputed items and must not be deducted from monthly statements of accounts.

Purchase of Goods and Services

Records of purchases made with Purchasing Cards must be forwarded to Accounts Payable by cardholders for audit trail purposes and to facilitate payment, reconciliation

and account verification (i.e., Purchasing Card Purchases Record, sales slips, credit vouchers, notices to vendors, etc.).

The appropriate sales tax exemption number/certificate must be provided to the vendor to ensure exemption from the provincial sales tax where applicable.

The appropriate Harmonized Sales Tax is to be paid where applicable.

For over-the-counter transactions, the cardholder will certify that the goods have been received or the services have been rendered by signing the sales slip, when goods are shipped, the cardholder must ensure that the shipment matches the order or sales slip.

For telephone orders, the cardholder must request the vendor to submit a copy of the sales slip with the shipment.

Purchasing Card Purchases Record

Supervisors shall ensure that a Purchasing Card Purchases Record is maintained (Reference Appendix O-Purchasing Card Purchases Record, Page 97), on a monthly basis, for all purchases made with Purchasing Cards as this record will:

- Facilitate the reconciliation of each items purchased during the month through the use of a Purchasing Card (i.e., telephone orders and over-the-counter transactions) with the monthly statement received from the bank;

- Expedite the coding of transactions (i.e., the description of the item and the account coding are included on the register for each item purchased);

- Make it easier for Supervisors to review and approve expenditures charged to their budget through the use of Purchasing Cards;

- Provide an appropriate monitoring tool for Supervisors with respect to expenditures incurred against their budget by employees with delegated purchasing authority for low-dollar-value purchases.

The information shown on the sample “Purchasing Card Purchases Record” (Reference Appendix O, Page 97) meets the “minimum” requirements.

Payment of Monthly Statements

The statement of accounts will be issued on the 21st day of each month and will be sent directly to Accounts Payable at the address indicated on the Bank Application Form.

Upon receipt of the statement for the current billing cycle, Accounts Payable must ensure that the statement is date stamped immediately in order to establish the “receipt date”. The due date is calculated 21 days following the monthly statement date.

The following documentation must be sent to Accounts Payable for payment purposes:

1. The monthly statement from the bank approved by the cardholder and the respective Vice President.

2. A copy of the Purchasing Card Purchases Record, including sales slips, credit vouchers, etc., approved by the cardholder, the Supervisor, the respective Vice President and the Administrator with the detailed purchases listed on the record must match the charges shown on the monthly statement with adjusting entries shown, as need be, for disputed items (bank errors) and purchases not yet processed by the bank.

3. The approved monthly statements and purchasing card purchases record must be sent to accounts payable for payment within 10 days after the due date printed on the statement in order that the month end entries can be made in a timely fashion.

Refunds from Vendors

When merchandise is returned or other adjustments to accounts are necessary, credit vouchers will be issued by vendors. Such credits must be issued against the same Purchasing Card that the original transaction was charged to.

Payment and Calculation of Interest

In accordance with the terms of the agreement between the bank and Thunder Bay Hydro, the payment of interest to the bank is based on a 21-day payment period. Where Thunder Bay Hydro is responsible for the delay, interest will be automatically calculated and paid on overdue accounts.

Where interest is payable, it will be calculated as follows:

- Consolidated statement from the date of the statement of account until the date payment is received by the bank and is a corporate charge;

- Individual statement – from the date of the purchase until the date payment is received by the bank and is a Divisional charge.

The rate of interest payable will be 18.20%. The bank reserves the right to change the rate from time to time upon 30 days written notice from the bank to Thunder Bay Hydro.

Card Renewal

Each Purchasing Card is issued for a period of two (2) years starting with the month in which the card is issued. Cards will be automatically renewed unless the bank is advised otherwise by Thunder Bay Hydro's Administrator.

Management Reports

The management reports produced by the bank are available to the Supervisors and the Administrator on a monthly basis for monitoring purposes. These reports are maintained in the Finance Division.

5.16.5 REFERENCE

Appendix M - Purchasing Card Application Form
Appendix N - Purchasing Acknowledgement of Responsibilities and Obligations
Appendix O - Purchasing Card Purchases Record
Appendix P - Purchasing Card Request for Change Form

Appendix 4-C

Post-Retirement Benefit Report

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Actuaries and Consultants

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THUNDER BAY HYDRO

REPORT ON THE ACTUARIAL VALUATION OF POST-EMPLOYMENT BENEFITS (VESTED SICK LEAVE PLAN)

As At January 1, 2010

FINAL (Revised)—March 4, 2011

Dion Durrell

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EXECUTIVE SUMMARY

PURPOSE

MEARIE Actuarial Services and Dion, Durrell + Associates Inc. were engaged by Thunder Bay Hydro (the "Corporation") to perform an actuarial valuation of the post-employment benefits sponsored by the Corporation, as identified by the Corporation or its auditors and to determine the accounting results for those benefit for the fiscal period ending December 31, 2010. The nature of these benefits is defined benefit.

This report is prepared in accordance with The Canadian Institute of Chartered Accountants (the "CICA") guidelines outlined in Employee Future Benefits, Section 3461 of the CICA Handbook – Accounting (CICA Section 3461). CICA Section 3461 was first applied to the Corporation with effect from January 1, 2000.

The most recent full valuation was prepared as at January 1, 2007 based on the then appropriate assumptions.

The purpose of this valuation is threefold:

i) to determine the Corporation's liabilities in respect of post-employment (vested sick leave) benefits at January 1, 2010;

ii) to determine the benefit expense for fiscal year 2010; and

iii) to provide all other pertinent information necessary for compliance with CICA 3461.

The intended users of this report include the Corporation and their auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

SUMMARY OF KEY RESULTS

The Accrued Benefits Obligation (ABO) as at January 1, 2010 is determined to be approximately $802,000. The total Current Service Cost for the fiscal year ending December 31, 2010 is determined to be approximately $15,000.

We have determined the cash value of the benefit as at January 1, 2010 to be approximately $873,000. The cash value is the total value required if benefits were paid out at January 1, 2010 at the rate at which the employees would be entitled.

A summary of the valuation results is shown in Section A of this report. The participant data and plan provisions are summarized in Section B of this report and the actuarial method and assumptions used to determine the ABO are described in detail in Section C of this report.

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ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the vested sick leave benefit plan sponsored by the Corporation as at January 1, 2010, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;

2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations). We have reviewed the assumptions and consider them to be appropriate for the purposes of the valuation outlined herein;

3. The actuarial methods employed, as outlined in Section C, are appropriate for the purpose and consistent with sound actuarial principles;

4. All known substantive commitments with respect to the post-employment benefits sponsored by and identified by the Corporation are included in the calculations; and

5. The valuation conforms to the standards set out in the Canadian Institute of Chartered Accountants Accounting Handbook Section 3461.

We are not aware of any subsequent events from January 1, 2010 up to the date of this report that would have a significant effect on our valuation.

The latest date on which the next actuarial valuation should be performed is January 1, 2013. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,

DION, DURRELL + ASSOCIATES INC.

Stanley Caravaggio

Stanley Caravaggio, FSA FCIA

Patrick G. Kavanagh

Patrick G. Kavanagh
Actuarial Analyst

Toronto, Ontario
March 4, 2011

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SECTION A
VALUATION RESULTS

Table A - 1 shows the key valuation results for the prior valuation and the current valuation.

Table A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed discount rate from 5.25% to 4.25% and without the use of a discount rate.

Table A - 3 presents the determination of the actuarial gain/(loss) from the previous valuation at January 1, 2007.

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VALUATION RESULTS

Table A.1—Valuation Results
(in thousands of dollars)

	January 1, 2007	January 1, 2010
1. Accrued Benefit Obligation		
Total ABO	**799**	**802**
2. Benefit Expense		
a) Current Service Cost	24	15
b) Interest Cost	42	40
c) Expected Return on Assets	-	-
d) Amortization of Transition Amount	-	-
e) Amount of Prior Service Cost	-	-
f) Amortization of (Gain)/Losses	49	65
Total Benefit Expense *for following 12 months*	**115**	**120**
3. Expected Benefit Payments *for following 12 months*	54	132

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SENSITIVITY ANALYSIS

Table A.2—Sensitivity Analysis
(in thousands of dollars)

		January 1, 2010		
		Valuation Results	4.25% Discount Rate	0.00% Discount Rate
1.	ABO as at January 1, 2010	802	829	969
2.	Current Service Cost	15	17	21
3.	Interest Cost	40	33	-
4.	Actuarial (Gain)/Loss	65	74	121
5.	Benefit Expense for 2010 *for following 12 months*	120	124	142
6.	Expected average remaining service lifetime of the current Active Employees (years)	3	3	3
7.	Projected Cash Value as at January 1, 2010 *	873	873	873

* The cash value in item number 7 is the total value required as at January 1, 2010 if benefits were paid out at the rate at which the employee would be entitled.

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DEVELOPMENT OF NET GAINS OR LOSSES

Table A.3—Development of Net Gains or Losses
(in thousands of dollars)

Expected ABO at December 31, 2009	644
Actual ABO at January 1, 2010	802
Actuarial Loss/(Gain)	158
Amortization of Unamortized Actuarial Loss	
Unamortized Net Actuarial Loss (Gain) at December 31, 2009	37
Actuarial Loss (Gain) for Current Year at January 1, 2010	158
Total Loss (Gain) at January 1, 2010	195
Less: Actual Amortization for 2010	(65)
Expected Unamortized Actuarial Loss (Gain) at December 31, 2010	130

Please note that the actual ABO at January 1, 2010 is approximately $158,000 higher than the expected ABO at December 31, 2009. This is due to a combination of the following factors:

- Changes in the valuation assumptions, including the discount rate, the mortality table, and the sick leave accumulation rate (an increase of approximately $39,000)
- Deviations from the expected demographic changes of the valued group and other miscellaneous factors (an increase of approximately $119,000 in the total ABO)

CICA Section 3461 requires entities to adopt a systematic method for recognizing actuarial gains and losses in income. Furthermore, once adopted, CICA Section 3461 requires that the method of recognizing actuarial (gains)/losses be applied consistently from year to year. In prior valuations, the Corporation has amortized the full amount of actuarial (gains)/losses over the Expected Average Remaining Service Lifetime ("EARSL") of the active employees in the valuation. The EARSL of the current active group is 3 years. Therefore, the actuarial loss to be recognized in 2010 is approximately $65,000.

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SECTION B
PLAN PARTICIPANTS

Section B – 1 presents a summary of the benefits provided under the plan.

Table B – 2 sets out the summary information with respect to the plan participants valued in the report, along with comparisons to the participants in the previous valuation at January 1, 2007 and a reconciliation of the number of participants in the last valuation to the number of participants in the current valuation.

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SUMMARY OF PLAN PROVISIONS

Section B.1—Summary of Plan Provisions

The following is a summary of the plan provisions that are pertinent to this valuation.

GOVERNING DOCUMENTS

The program is governed by Principle and Supplementary Agreements between Thunder Bay Hydro Electricity Distribution Inc. and Local Union 339 of the International Brotherhood of Electrical Workers (Office Staff, Outside Staff) in full force and effect from May 1, 2008 to April 31, 2010.

What follows is only a summary of the post-employment vested sick leave benefit program. For a complete description, please refer to the above-noted document.

ELIGIBILITY

All employees of the Hydro who were hired prior to May 1, 1986 with a minimum of 5 years of active service are eligible for post-employment sick leave benefits.

PARTICIPANT CONTRIBUTIONS

The Corporation shall pay 100% of the cost of the post-employment vested sick leave benefits for the eligible employees.

PAST SERVICE

Past service is defined as continuous service prior to joining the plan if the participant was employed with another electrical distribution company/hydro prior to joining the Corporation.

LENGTH OF SERVICE

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

SUMMARY OF BENEFITS

Credits shall accumulate at a rate of one and one-half days per calendar month. Sick leave credits are paid out in the event of early retirement only (retiring prior to age 65).

The plan provides for an equivalent credit to retirement as the number of accrued sick days less 75 days (a minimum 76 days of sick leave is required to access this option). The maximum credit to retirement under the plan is 150 days. Management/Non-Management Union staff officially have a choice to have the days paid out, or to run out the time right before retirement.

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SUMMARY OF PLAN PARTICIPANTS

Table B.2— Participant Data

Membership data as at January 1, 2010 was received from the Corporation via e-mail and included information such as name, sex, date of birth, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

Active Participants as of January 1		2007	2010
		Total	Total
1.	Total valued participants	36	29
2.	Total annual pay	$2,104,000	$1,776,000
3.	Average annual pay	$58,000	$61,000
4.	Average age	50.0	53.1
5.	Average service (years)	27.0	29.5
6.	Average annual utilization of sick days (days)*	4.1	8.0

* Average annual utilization calculated from the beginning of calendar year 2004 to the respective valuation date.

Data Checks Employed

In producing our valuation at January 1, 2010, we have employed the following data error checks in order to ensure the accuracy of the data presented:

- Date of birth prior to date of hire
- Salaries less than $20,000 per year, or greater than $250,000 per year
- Ages under 18 or over 100
- Accumulation of sick leave credits exceeding the allowable rates of accumulation
- Payouts of sick leave banks exceeding the allowable levels of payout
- Duplicate records

	Actives	LTD
As at January 1, 2007	**36**	-
New Entrants	-	-
Active	-	1
LTD	(1)	-
Terminated	(3)	-
Deceased	-	-
Retired	(4)	-
Correction	-	-
As at January 1, 2010	**28**	**1**

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SECTION C
SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

ACTUARIAL METHOD

The aim of an actuarial valuation of post-employment benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions as to the discount rates, salary increase rates, mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefit to the specific years of employment.

The ABO and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by CICA Section 3461 when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-employment benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. Section CICA 3461 stipulates that the attribution period is the employee's assumed period of service.

For each active employee, the ABO is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

The ABO at January 1, 2010 is based on membership data at January 1, 2010 and management's best-estimate assumptions at January 1, 2010.

ACCOUNTING POLICIES

Pursuant to CICA 3461, the Corporation amortizes the amount of any actuarial gains or losses over the expected average remaining service lifetime of the active employees.

MANAGEMENT'S BEST ESTIMATE ASSUMPTIONS

The following are management's best estimate economic and demographic assumptions as at January 1, 2010.

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ECONOMIC ASSUMPTIONS

Consumer Price Index

The consumer price index is assumed to be 2.00% per annum.

This is the same assumption used in the previous valuation.

Discount Rate

The rate used to discount future benefits is assumed to be 5.25% per annum. This rate reflects the market interest rates at the measurement date on high-quality debit instruments with consideration given to the timing and amount of projected benefit payments.

An assumption of 5.25% per annum was used in the previous valuation. More recently, this assumption was updated to 6.00% per annum for calculations as at December 31, 2009.

Salary Increase Rate

The rate used to increase salaries is assumed to be 3.30% per annum. This rate reflects the expected Consumer Price Index adjusted for productivity, merit and promotion.

This is the same assumption used in the previous valuation.

DEMOGRAPHIC ASSUMPTIONS

Annual Accumulation of Sick Leave

Future annual utilization of sick leave for the post-employment benefit is assumed to be 8.00 days per annum for all eligible employees. Annual earned sick days per annum for each employee will be based on the Corporation's benefit provisions and the assumption that all employees will earn at the full annual rate, i.e. 1.5 days per month. The future annual accumulation of vested sick leave for each employee will be equal to the annual earned sick days per annum minus the assumed sick leave utilization rate.

The assumption used in the previous valuation was a future annual accumulation of 4.10 days of vested sick leave per annum (equal to an average of 10.50 earned sick days per annum less an assumed sick leave utilization of 6.40 days of vested sick leave per annum), to a maximum accrual of 150 days.

Mortality Table

Mortality is assumed to be in accordance with the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2020 based upon Projection Scale AA. The use of these rates seems reasonable given this is the mortality table to be used in accordance with the Canadian Institute of Actuaries' Standard of Practice for Determining Pension Commuted Values, effective April 1, 2009.

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Mortality rates are applied on a sex-distinct basis.

The prior valuation used the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2015 based upon Projection Scale AA.

Rates of Withdrawal

Termination of employment prior to age 55 was assumed to be equal to 2.00% per annum. This is the same assumption used in the prior valuation.

Retirement Age

All active employees are assumed to retire at age 57, or immediately if currently over age 57.

This assumption remains unchanged from the previous valuation.

Disability

No provision was made for future disability. It is assumed that individuals currently receiving long-term disability benefits will remain disabled until retirement at age 65. This assumption remains unchanged from the previous valuation.

Expenses and Taxes

We have assumed 5.00% of benefits is required for the cost of sponsoring the program. This is the same assumption that was used in the previous valuation.

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SECTION D
EMPLOYER CERTIFICATION

Post-employment (Vested Sick Leave) Benefit Plan
of the Thunder Bay Hydro
Actuarial Valuation as at January 1, 2010

I hereby confirm as an authorized signing officer of the administrator of the Post-Employment Vested Sick Leave Benefit Plan of Thunder Bay Hydro that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the membership data summarized in Section B is accurate and complete;

ii) the summary of Plan Provisions in Section B is an accurate and complete summary of the terms of the Plan in effect on January 1,2010; and

iii) the assumptions upon which this report is based as summarized in Section C are management best estimate assumptions and are adequate and appropriate for the purposes of this valuation.

THUNDER BAY HYDRO

Oct 4 2011
Date

Cindy Speziale
Signature

Cindy Speziale
Name

Vice President, Finance
Title

Appendix 4-D

2011 Federal & Ontario Tax Return

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

CLIENT COPY

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 89209 0614 RC0001

Corporation's name
002 Thunder Bay Hydro Electricity Distribution Inc.

Address of head office
Has this address changed since the last time we were notified? 010 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 011 to 018.)
011 34 N. Cumberland Street
012
City: 015 Thunder Bay
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 P7A 4L4

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? 020 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

Location of books and records
Has the location of books and records changed since the last time we were notified 030 1 Yes ☐ 2 No ☒
(If **yes**, complete lines 031 to 038.)
031 34 N. Cumberland Street
032
City: 035 Thunder Bay
Province,territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 P7A 4L4

040 **Type of corporation at the end of the tax year**
1 ☒ Canadian-controlled private corporation (CCPC)
2 ☐ Other private corporation
3 ☐ Public corporation
4 ☐ Corporation controlled by a public corporation
5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 YYYY MM DD

To which tax year does this return apply?
Tax year start 060 2011-01-01 YYYY MM DD
Tax year-end 061 2011-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? 063 1 Yes ☐ 2 No ☒
If **yes**, provide the date control was acquired 065 YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with:
subparagraph 88(2)(a)(iv)? 064 1 Yes ☐ 2 No ☒
subsection 249(3.1)? 066 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? 067 1 Yes ☐ 2 No ☒

Is this the first year of filing after:
Incorporation? 070 1 Yes ☐ 2 No ☒
Amalgamation? 071 1 Yes ☐ 2 No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? 072 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? 076 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? 078 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?
080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? 082 1 Yes ☐ 2 No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 ☐ Exempt under paragraph 149(1)(e) or (l)
2 ☐ Exempt under paragraph 149(1)(j)
3 ☐ Exempt under paragraph 149(1)(t)
4 ☐ Exempt under other paragraphs of section 149

Do not use this area
095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Was the resident corporation the beneficiary of a non-resident discretionary trust or did it make a contribution to a non-resident discretionary trust at any time during the tax year?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricty Distribu	285	97.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes	2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.		300	3,021,088	A
Deduct: Charitable donations from Schedule 2	311	16,786		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		16,786 ▶	16,786	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			3,004,302	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions		355		D
Taxable income (amount C **plus** amount D)		360	3,004,302	
Income exempt under paragraph 149(1)(t)		370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			3,004,302	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	3,021,088	A
Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632* on page 7, **minus** 1/(0.38 - X**) 3.77358 times the amount on line 636*** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	3,004,302	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 **** 212,657 / 11,250 D = 9,451,422 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 F

Small business deduction

Amount A, B, C, or F, whichever is the least x 17 % = 430 G

Enter amount G on line 1 on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. It has to be pro-rated.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

**** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3		3,004,302	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			B
Amount QQ from Part 13 of Schedule 27			C
Amount used to calculate the credit union deduction from Schedule 17			D
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			E
Aggregate investment income from line 440 on page 6*			F
Total of amounts B to F	▶		G
Amount A **minus** amount G (if negative, enter "0")		3,004,302	H

Amount H	3,004,302	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365	x	9 %	=		I
Amount H	3,004,302	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365	x	10 %	=		J
Amount H	3,004,302	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	345,495	K
Amount H	3,004,302	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365	x	13 %	=		L

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L . . . . . 345,495 M

Enter amount M on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			O
Amount QQ from Part 13 of Schedule 27			P
Amount used to calculate the credit union deduction from Schedule 17			Q
Total of amounts O to Q	▶		R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365	x	9 %	=		T
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365	x	10 %	=		U
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=		V
Amount S		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365	x	13 %	=		W

General tax reduction – Total of amounts T to W X

Enter amount X on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . . 440 _____ x 26 2 / 3 % = ... _____ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . _____

Deduct:

Foreign investment income from Schedule 7 . . . . . 445 _____ x 9 1 / 3 % = _____

(if negative, enter "0") _____ ▶ _____ B

Amount A **minus** amount B (if negative, enter "0") . . . . . _____ C

Taxable income from line 360 on page 3 3,004,302

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . _____

Foreign non-business income tax credit from line 632 on page 7 . . . _____ x 25 / 9 = _____

Foreign business income tax credit from line 636 on page 7 . . . . . _____ x 1(0.38 - X*) / 3.77358 = _____

_____ ▶ _____

3,004,302

x 26 2 / 3 % = 801,147 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . 495,710 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . . 450 _____ F

* General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . 460 _____

Deduct: Dividend refund for the previous tax year . . . . . 465 _____

_____ ▶ _____ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . . _____

Total Part IV tax payable from Schedule 3 . . . . . _____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . 480 _____

_____ ▶ _____ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . . 485 _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . _____ x 1 / 3 _____ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . _____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) . . . . . _____

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % 550 1,141,635 A

Recapture of investment tax credit from Schedule 31 . . . . . 602 B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 i

Taxable income from line 360 on page 3 3,004,302

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . .

Net amount . . . . . 3,004,302 ▶ 3,004,302 ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . 604 C

Subtotal (**add** lines A to C) 1,141,635 D

Deduct:

Small business deduction from line 430 on page 4 1

Federal tax abatement 608 300,430

Manufacturing and processing profits deduction from Schedule 27 616

Investment corporation deduction 620

Taxed capital gains 624

Additional deduction – credit unions from Schedule 17 628

Federal foreign non-business income tax credit from Schedule 21 632

Federal foreign business income tax credit from Schedule 21 636

General tax reduction for CCPCs from amount M on page 5 . . . . . 638 345,495

General tax reduction from amount X on page 5 639

Federal logging tax credit from Schedule 21 640

Federal qualifying environmental trust tax credit 648

Investment tax credit from Schedule 31 652

Subtotal 645,925 ▶ 645,925 E

Part I tax payable – Line D **minus** line E . . . . . 495,710 F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	495,710
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		495,710

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	210,841	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
		210,841 ▶	210,841
Total tax payable	770		706,551 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	1,000,028	
Total credits	890	1,000,028 ▶	1,000,028 B

Refund code 894 1 Overpayment 293,477

Balance (line A **minus** line B) -293,477

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . .

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . . . 896 1 Yes ☐ 2 No ☒

Certification

I, 950 Speziale (Last name in block letters) 951 Cindy (First name in block letters) 954 Vice President - Finance (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-04-20 Date (yyyy/mm/dd) Signature of the authorized signing officer of the corporation 956 (807) 343-1118 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . . . 957 1 Yes ☒ 2 No ☐

958 Name in block letters 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Privacy Act, Personal Information Bank number CRA PPU 047

Schedule of Instalment Remittances

Name of corporation contact _____

Telephone number _____

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
2011-01-14	Instalments	76,387
2011-02-11	Installment	76,387
2011-03-04	Installment	76,387
2011-04-11	Installment	76,387
2011-05-11	Installment	76,387
2011-06-02	Installment	76,387
2011-07-14	Installment	17,515
2011-08-22	Installment	17,515
2011-09-07	Installment	61,669
2011-10-12	Installment	61,669
2011-12-12	Installment	61,669
2012-03-31	Installment	260,000
2011-11-16	installment	61,669
	Total amount of instalments claimed (carry the result to line 840 of the T2 Return)	1,000,028 **A**
	Total instalments credited to the taxation year per T9	1,000,028 **B**

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	31,981,726	31,123,242
	Total tangible capital assets	2008	+	155,156,722	147,717,330
	Total accumulated amortization of tangible capital assets	2009	–	87,500,532	82,936,584
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	14,700,815	14,805,590
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	114,338,731	110,709,578
Liabilities					
	Total current liabilities	3139	+	17,012,570	16,881,234
	Total long-term liabilities	3450	+	49,946,241	48,478,815
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	66,958,811	65,360,049
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	47,379,920	45,349,529
	Total liabilities and shareholder equity	3640	=	114,338,731	110,709,578
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	12,448,295	10,417,904

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

Income statement information

Description	GIFI

Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	103,377,657	95,171,784
	Cost of sales	8518	–	85,875,693	78,674,166
	Gross profit/loss	8519	=	17,501,964	16,497,618
	Cost of sales	8518	+	85,875,693	78,674,166
	Total operating expenses	9367	+	17,169,597	17,728,566
	Total expenses (mandatory field)	9368	=	103,045,290	96,402,732
	Total revenue (mandatory field)	8299	+	105,737,556	97,137,764
	Total expenses (mandatory field)	9368	–	103,045,290	96,402,732
	Net non-farming income	9369	=	2,692,266	735,032
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	2,692,266	735,032
	Total other comprehensive income	9998	=		
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	706,875	580,000
	Deferred income tax provision	9995	–	-45,000	-326,500
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	2,030,391	481,532

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SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide.*
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . . . **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client) . . . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . . . 2 [ ]

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [ ] 2 No [X]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . . **250** 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				2,030,391 A
Add:				
Provision for income taxes – current		101	706,875	26922166
Provision for income taxes – deferred		102	-45,000	
Amortization of tangible assets		104	5,032,895	
Charitable donations and gifts from Schedule 2		112	16,786	
Non-deductible meals and entertainment expenses		121	17,993	
Subtotal of additions			5,729,549 ▶	5,729,549
Other additions:				
Miscellaneous other additions:				
600 Smart Meter net revenues		290	1,067,020	
603 Ontario Specified Tax Credits	105,863			
Total	105,863	293	105,863	
604 Regulatory Asset Recovery	196,244			
Total	196,244	294	196,244	
Subtotal of other additions		199	1,369,127 ▶	1,369,127
Total additions		500	7,098,676 ▶	7,098,676
Deduct:				
Gain on disposal of assets per financial statements		401	25,451	
Capital cost allowance from Schedule 8		403	5,810,032	
Cumulative eligible capital deduction from Schedule 10		405	66,684	
Subtotal of deductions			5,902,167 ▶	5,902,167
Other deductions:				
Miscellaneous other deductions:				
700 IFRS Implementation Cost Deferrals		390	42,993	
701 Regulatory Asset Deductions		391	12,773	
704 ARO expenses	32,077			
Future Employee Benefits	117,969			
Total	150,046	394	150,046	
Subtotal of other deductions		499	205,812 ▶	205,812
Total deductions		510	6,107,979 ▶	6,107,979
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				3,021,088

T2 SCH 1 E (10)

Canada

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SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return.*
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
See list attached	16,786
Subtotal	16,786
Add: Total donations of less than $100 each	
Total donations in current tax year	16,786

		Federal		Québec	Alberta
Charitable donations at the end of the previous tax year					
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the tax year	240				
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1)	210	16,786			
Subtotal (line 250 **plus** line 210)		16,786		16,786	16,786
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255				
Total charitable donations available		16,786	A	16,786	16,786
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260	16,786		16,786	16,786
Charitable donations closing balance	280				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2000-12-31			
12th prior year	1999-12-31			
13th prior year	1998-12-31			
14th prior year	1997-12-31			
15th prior year	1996-12-31			
16th prior year	1995-12-31			
17th prior year	1994-12-31			
18th prior year	1993-12-31			
19th prior year	1992-12-31			
20th prior year	1991-12-31			
21st prior year*	1990-12-31			
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % ..... 2,265,816 B

Taxable capital gains arising in respect of gifts of capital property included in Part 1** ..... 225 _____ C

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ..... 227 _____ D

The amount of the recapture of capital cost allowance in respect of charitable gifts ..... 230 _____

Proceeds of disposition, less outlays and expenses** ..... _____ E

Capital cost** ..... _____ F

Amount E or F, whichever is less ..... 235 _____

Amount on line 230 or 235, whichever is less ..... _____ G

Subtotal (**add** amounts C, D, and G) _____ H

Amount H **multiplied** by 25 % _____ I

Subtotal (amount B **plus** amount I) 2,265,816 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) ..... 16,786 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year			
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		▶
Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory*	310		
Subtotal (line 350 **plus** line 310)			
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	355		
Total gifts to Canada, a province, or a territory available			
Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return).	360		
Gifts to Canada, a province, or a territory closing balance	380		

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years*	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2000-12-31			
12th prior year	1999-12-31			
13th prior year	1998-12-31			
14th prior year	1997-12-31			
15th prior year	1996-12-31			
16th prior year	1995-12-31			
17th prior year	1994-12-31			
18th prior year	1993-12-31			
19th prior year	1992-12-31			
20th prior year	1991-12-31			
21st prior year*	1990-12-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years*	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2000-12-31			
12th prior year	1999-12-31			
13th prior year	1998-12-31			
14th prior year	1997-12-31			
15th prior year	1996-12-31			
16th prior year	1995-12-31			
17th prior year	1994-12-31			
18th prior year	1993-12-31			
19th prior year	1992-12-31			
20th prior year	1991-12-31			
21st prior year*	1990-12-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal	Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639			
Additional deduction for gifts of medicine at the beginning of the tax year	640			
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650			
Additional deduction for gifts of medicine for the current year:				
Proceeds of disposition	602	1	1	1
Cost of gifts of medicine	601	2	2	2
Subtotal (line 1 **minus** line 2)		3	3	3
Line 3 **multiplied** by 50 %		4	4	4
Eligible amount of gifts	600	5	5	5

Federal
A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year **610** _____

Québec
A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

Alberta
A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

where:
A is the **lesser** of line 2 and line 4
B is the eligible amount of gifts (line 600)
C is the proceeds of disposition (line 602)

		Federal	Québec	Alberta
Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
Total				

* These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2010-12-31	
2nd prior year	2009-12-31	
3rd prior year	2008-12-31	
4th prior year	2007-12-31	
5th prior year	2006-12-31	
6th prior year*	2005-12-31	
7th prior year	2004-12-31	
8th prior year	2003-12-31	
9th prior year	2002-12-31	
10th prior year	2001-12-31	
11th prior year	2000-12-31	
12th prior year	1999-12-31	
13th prior year	1998-12-31	
14th prior year	1997-12-31	
15th prior year	1996-12-31	
16th prior year	1995-12-31	
17th prior year	1994-12-31	
18th prior year	1993-12-31	
19th prior year	1992-12-31	
20th prior year	1991-12-31	
21st prior year*	1990-12-31	
Total		

* These gifts expired in the current year.

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 _____ Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act.*

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide.*
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
3,004,302		3,004,302	316,704

Ontario basic income tax (from Schedule 500)	270	352,944		
Deduct: Ontario small business deduction (from schedule 500)	402	36,240		
Subtotal		316,704	316,704	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272			
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal				B6
Subtotal (amount A6 **plus** amount B6)			316,704	C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414			
Ontario political contributions tax credit (from Schedule 525)	415			
Subtotal				D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			316,704	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			316,704	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)	418			
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			316,704	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282			
Subtotal				H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			316,704	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452			
Ontario apprenticeship training tax credit (from Schedule 552)	454	105,863		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Other Ontario tax credits				
Subtotal		105,863	105,863	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		210,841	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 210,841

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	10	Rolling Stock/Comp	1,566,738	399,566		20,000	189,783	1,756,521	30	0	0	526,956	1,419,348
2.	8	Office/Other Equip	791,971	176,603		7,075	84,764	876,735	20	0	0	175,347	786,152
3.	4	Building	1,669,542			0		1,669,542	6	0	0	100,173	1,569,369
4.	47	Distribution Equipment Post Feb	28,845,078	6,137,292	-322,110	0	3,068,646	31,591,614	8	0	0	2,527,329	32,132,931
5.	45	Computer Equipment acquired af	13,651			0		13,651	45	0	0	6,143	7,508
6.	1	Distribution Equipment	52,100,366			0		52,100,366	4	0	0	2,084,015	50,016,351
7.	50	Computer Equip Sub to Mar 18, :	38,451	99,528		0	49,764	88,215	55	0	0	48,518	89,461
8.	13	Leasehold Improvements		2,473		0	1,237	1,236	NA	0	0	247	2,226
9.	12	Application Software		38,388		0	19,194	19,194	100	0	0	19,194	19,194
10.	52	Computer Hardware/Software			322,110	0		322,110	100	0	0	322,110	
		Totals	85,025,797	6,853,850		27,075	3,413,388	88,439,184				5,810,032	86,042,540

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide.*

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Thunder Bay Hydro Corporation		86523 2995 RC0001	1	1,000	100.000			34,931,625
2.	Thunder Bay Renewable Power Incc		86170 7461 RC0001	3					
3.	Thunder Bay Hydro Utility Services I		86189 1059 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 952,626 A

Add:

Cost of eligible capital property acquired during the taxation year . . . . . **222** _____

Other adjustments . . . . . **226** _____

Subtotal (line 222 plus line 226) _____ x 3 / 4 = _____ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** _____ x 1 / 2 = _____ C

amount B minus amount C (if negative, enter "0") _____ ▶ _____ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . **224** _____ E

Subtotal (add amounts A, D, and E) **230** 952,626 F

Deduct:

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . **242** _____ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** _____ H

Other adjustments . . . . . **246** _____ I

(add amounts G,H, and I) _____ x 3 / 4 = **248** _____ J

Cumulative eligible capital balance (amount F minus amount J) . . . . . 952,626 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . . . **249** _____

amount K 952,626

less amount from line 249 _____

Current year deduction . . . . . 952,626 x 7.00 % = **250** 66,684 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 66,684 ▶ 66,684 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 885,942 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)		401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4		
Line 3 minus line 4 (if negative, enter "0")			▶	5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8		
Subtotal (line 7 plus line 8)	409		▶	9	
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
Line 5		× 1 / 2 =			Q
Line P minus line Q (if negative, enter "0")					R
Amount R		× 2 / 3 =			S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)		410			

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)

2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction

3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)

4 – Associated non-CCPC

5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . **050** Year 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** 1 Yes ☐ 2 No ☒

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	1	500,000	100.0000	500,000
2	Thunder Bay Hydro Corporation	86523 2995 RC0001	1	500,000		
3	Thunder Bay Renewable Power Incorporated	86170 7461 RC0001	1	500,000		
4	Thunder Bay Hydro Utility Services Inc.	86189 1059 RC0001	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

  Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (09)

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	Thunder Bay Hydro Corporation	86523 2995 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

On: 2011-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	10,986,875 A
Taxable income for the year (DICs enter "0") *	110	3,004,302 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140			
Subtotal (**add** lines 120, 130, and 140)		▶ C		
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	3,004,302		
After-tax income (line 150 x general rate factor for the tax year ** 0.7)			190	2,103,011 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (**add** lines 200 and 210)		▶		E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (**add** lines 220, 230, and 240)		▶	290	F
Subtotal (**add** lines A, D, E, and F)				13,089,886 G
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.				
Subtotal (line 300 **minus** line 310)		▶		H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)			490	13,089,886
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	13,089,886

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year	2,205,447 J1		
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)	▶	N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")	2,205,447	▶	2,205,447 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . . _____ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ R1

Aggregate investment income (line 440 of the T2 return) . . . . . _____ S1

Subtotal (**add** lines Q1, R1, and S1) _____ ▶ _____ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") _____ ▶ _____ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") _____ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.7) . . . . . **500** _____

Second previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year 2,556,172 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ L2

Aggregate investment income (line 440 of the T2 return) . . . . . _____ M2

Subtotal (**add** lines K2, L2, and M2) _____ ▶ _____ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 2,556,172 ▶ 2,556,172 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . . _____ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ R2

Aggregate investment income (line 440 of the T2 return) . . . . . _____ S2

Subtotal (**add** lines Q2, R2, and S2) _____ ▶ _____ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") _____ ▶ _____ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") _____ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.7) . . . . . **520** _____

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 2,818,713 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ L3

Aggregate investment income (line 440 of the T2 return) . . . . . _____ M3

Subtotal (**add** lines K3, L3, and M3) _____ ▶ _____ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 2,818,713 ▶ 2,818,713 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . . _____ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ R3

Aggregate investment income (line 440 of the T2 return) . . . . . _____ S3

Subtotal (**add** lines Q3, R3, and S3) _____ ▶ _____ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") _____ ▶ _____ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") _____ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.7) . . . . . **540** _____

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . _____ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . _____ AA

Eligible dividends paid by the corporation in its last tax year . . . . . _____ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . _____ CC

Subtotal (line BB **minus** line CC) _____ ▶ _____ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . . _____ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC ☐ Post amalgamation ☐ Post wind-up ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year		FF
The corporation's money on hand immediately before the end of its previous/last tax year		GG
Unused and unexpired losses at the end of the corporation's previous/last tax year:		
Non-capital losses		
Net capital losses		
Farm losses		
Restricted farm losses		
Limited partnership losses		
Subtotal	▶	HH
Subtotal (**add** lines FF, GG, and HH)		II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year	JJ	
Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year	KK	
All the corporation's reserves deducted in its previous/last tax year	LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year	MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year	NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)	▶	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")		PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year		365	=		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year		365	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	365	365	=	0.70000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year		365	=		TT

General rate factor for the tax year (total of lines QQ to TT) . . . . . 0.70000 UU

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references on this schedule are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year		x	14.00 %	=	%	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	12.00 %	=	5.95068 %	A2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	184 / 365	x	11.50 %	=	5.79726 %	A3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year		x	11.00 %	=	%	A4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year		x	10.00 %	=	%	A5

Ontario basic rate of tax for the year (total of rates A1 to A5) 11.74794 ▶ 11.74794 % A6

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 3,004,302 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A6 from Part 1) . . . . . 352,944 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)					3,021,088	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)					3,004,302	2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)	500,000	x	500,000 / 500,000 (line 4 on page 4 of the T2 return *)	=	500,000	3
Enter the least of amounts 1, 2, and 3					500,000	D
Ontario domestic factor:	Ontario taxable income ** / taxable income earned in all provinces and territories ***		3,004,302.00 / 3,004,302	=	1.00000	E

Amount D x amount E	500,000	a
Ontario taxable income (amount B from Part 2)	3,004,302	b

Ontario small business income (lesser of amount a and amount b)					500,000	F
Number of days in the tax year before July 1, 2010 / Number of days in the tax year	365	x	8.50 %	=	%	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	7.50 %	=	3.71918 %	G2
Number of days in the tax year after June 30, 2011, and before July 1, 2012 / Number of days in the tax year	184 / 365	x	7.00 %	=	3.52877 %	G3
Number of days in the tax year after June 30, 2012, and before July 1, 2013 / Number of days in the tax year	365	x	6.50 %	=	%	G4
Number of days in the tax year after June 30, 2013 / Number of days in the tax year	365	x	5.50 %	=	%	G5
OSBD rate for the year (total of rates G1 to G5)					7.24795 %	G6
Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G6)					36,240	H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction.*

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income * I

Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501) . . . . J

Aggregate adjusted taxable income (amount I **plus** amount J) . . . . . ▶ K

Deduct:

Ontario business limit 500,000

Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P) L

Small business surtax rate for the year:

$\frac{\text{Number of days in the tax year before July 1, 2010}}{\text{Number of days in the tax year}}$ $\frac{\quad}{365}$ x 4.25 % = % M

Amount L x % on line M = ... N

Amount N x $\frac{\text{Ontario small business income (amount F from Part 3)}}{500{,}000}$ $\frac{\quad}{500{,}000}$ = ... O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) . . . . . P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 . . . . . 500,000 Q

$\frac{\text{Surtax payable (amount P from Part 4)}}{\text{Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3)}}$ 7.24795 % $\frac{\quad}{0.07248}$ = R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") . . . . . 500,000 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			T
Deduct:			
Ontario adjusted small business income (amount S from Part 5)			U
Subtotal (amount T **minus** amount U) (if negative, enter "0")			V
OSBD rate for the year (rate G6 from Part 3)	7.24795 %		
Amount V **multiplied** by the OSBD rate for the year			W
Ontario domestic factor (amount E from Part 3)		1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)			Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	114,338,731
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	49,510,759
Total assets (total of lines 112 to 116)		163,849,490
Total revenue of the corporation for the tax year **	142	105,737,556
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	3,268,453
Total revenue (total of lines 142 to 146)		109,006,009

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *				210	2,030,391
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220	706,875			
Provision for deferred income taxes (debits)/cost of future income taxes	222				
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228				
Total patronage dividends received, not already included in net income/loss	232				
281	282				
283	284				
Subtotal		706,875	▶		706,875 A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320				
Provision for deferred income taxes (credits)/benefit of future income taxes	322	45,000			
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326				
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336				
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381	382				
383	384				
385	386				
387	388				
389	390				
Subtotal		45,000	▶		45,000 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)				490	2,692,266

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.
- Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.
- Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)	515	2,692,266
Deduct:		
CMT loss available (amount R from Part 7)		
Minus: Adjustment for an acquisition of control *	518	
Adjusted CMT loss available		C
Net income subject to CMT calculation (if negative, enter "0")	520	2,692,266

Amount from line 520	2,692,266	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	x 4 % =		1
Amount from line 520	2,692,266	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	365 / 365 x 2.7 % =	72,691	2
			Subtotal (amount 1 **plus** amount 2)		72,691	3

Gross CMT: amount on line 3 above x OAF **	540	72,691	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		72,691	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		316,704	✓
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** = _____

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year * . . . . . G

Deduct:

CMT credit expired * 600

CMT credit carryforward at the beginning of the current tax year * (see note below) . . . . . ▶ 620

Add:

CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) 650

CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) . . . . . H

Deduct:

CMT credit deducted in the current tax year (amount P from Part 5) I

Subtotal (amount H **minus** amount I) J

Add:

Net CMT payable (amount E from Part 3) . . . . . .

SAT payable (amount O from Part 6 of Schedule 512) . . . . . .

Subtotal ▶ K

CMT credit carryforward at the end of the tax year (amount J **plus** amount K) . . . . . 670 L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4) . . . . . M

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 316,704 1

For a corporation that is not a life insurance corporation:

CMT after foreign tax credit deduction (amount D from Part 3) . . 72,691 2

For a life insurance corporation:

Gross CMT (line 540 from Part 3) 3

Gross SAT (line 460 from Part 6 of Schedule 512) 4

The **greater** of amounts 3 and 4 5

Deduct: line 2 or line 5, whichever applies: 72,691 6

Subtotal (if negative, enter "0") 244,013 ▶ 244,013 N

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 316,704

Deduct:

Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) 105,863

Subtotal (if negative, enter "0") 210,841 ▶ 210,841 O

CMT credit deducted in the current tax year (least of amounts M, N, and O) . . . . . P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? . . . . . 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Thunder Bay Hydro Corporation	86523 2995 RC0001	37,522,072	52,880
2	Thunder Bay Renewable Power Incorporated	86170 7461 RC0001	10,380,313	2,528,227
3	Thunder Bay Hydro Utility Services Inc.	86189 1059 RC0001	1,608,374	687,346
		Total	450 49,510,759	550 3,268,453

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009* or the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
Cindy Speziale	(807) 343-1118

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes ☐ 2 No ☒

If **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** _____

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 9,920,344

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \frac{(\text{amount on line 300} \ \textbf{minus}\ 400{,}000)}{200{,}000} \right]$$

Specified percentage . . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \frac{(\text{amount on line 300} \ \textbf{minus}\ 400{,}000)}{200{,}000} \right]$$

Specified percentage . . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
1.	434a	Powerline Technician	Greg Major
2.	434a	Powerline Technician	Dustin Nyberg
3.	434a	Powerline Technician	Graem Nelson
4.	434a	Powerline Technician	Morgan Cederwall
5.	434a	Powerline Technician	Tyler Deley
6.	434a	Powerline Technician	Cameron McWhirter
7.	434a	Powerline Technician	Darcy Raison
8.	434a	Powerline Technician	Jeremy Puhalski
9.	434a	Powerline Technician	Brennan Harri
10.	434a	Powerline Technician	James Pantontin
11.	434a	Powerline Technician	Philip Bevilacqua
12.	434a	Powerline Technician	Jonathon Hay
13.			

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	PA4812	2008-06-04	2011-01-01	2011-12-31
2.	PA4802	2008-06-04	2011-01-01	2011-12-31
3.	A80502	2008-02-12	2011-01-01	2011-01-06
4.	PC5446	2009-04-29	2011-01-01	2011-12-31
5.	D26075	2009-01-12	2011-01-01	2011-12-31
6.	PC5453	2009-06-11	2011-01-01	2011-12-31
7.	PC5437	2009-04-03	2011-01-01	2011-12-31

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
8.	PA9025	2010-01-11	2011-01-01	2011-12-31
9.	PC5829	2010-02-19	2011-01-01	2011-12-31
10.	Pc5828	2010-02-19	2011-01-01	2011-12-31
11.	PC7717	2011-01-10	2011-01-01	2011-12-31
12.	PB1870	2011-06-06	2011-06-06	2011-12-31
13.				

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		365	365	10,000
2.		365	365	10,000
3.		6	6	164
4.		365	365	10,000
5.		365	365	10,000
6.		365	365	10,000
7.		365	365	10,000
8.		365	365	10,000
9.		365	365	10,000
10.		365	365	10,000
11.		365	365	10,000
12.		208	208	5,699
13.				

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		70,898	70,898	24,814
2.		82,858	82,858	29,000
3.		1,038	1,038	363
4.		56,866	56,866	19,903
5.		76,518	76,518	26,781
6.		61,192	61,192	21,417
7.		60,072	60,072	21,025
8.		65,908	65,908	23,068
9.		55,897	55,897	19,564
10.		55,658	55,658	19,480
11.		50,708	50,708	17,748
12.		39,369	39,369	13,779
13.				

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	10,000		10,000
2.	10,000		10,000
3.	164		164
4.	10,000		10,000
5.	10,000		10,000
6.	10,000		10,000
7.	10,000		10,000
8.	10,000		10,000
9.	10,000		10,000
10.	10,000		10,000
11.	10,000		10,000
12.	5,699		5,699

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
13.			

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 105,863 O

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O _____ x percentage on line 170 in Part 1 _____ % = ... _____ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Canada Revenue Agency | Agence du revenu du Canada

INFORMATION RETURN FOR CORPORATIONS FILING ELECTRONICALLY

CLIENT COPY

- You have to complete this return to allow your transmitter to electronically file your corporation income tax return to us at the Canada Revenue Agency. You have to complete this return for each tax year.
- By completing part B and signing part C, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part D must be completed by either you or the electronic transmitter of your corporation income tax return.
- Give the signed original of this return to the transmitter and keep a copy for yourself. Under the Act, you have to keep your copy for six years.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

This return is for your records. Do not send it to us unless we ask for it.

Part A – Identification

Name of corporation			
Thunder Bay Hydro Electricity Distribution Inc.			
Business Number	Tax year ▶	From Y M D	To Y M D
89209 0614 RC0001		2011-01-01	2011-12-31

Part B – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

Net income or (loss) for income tax purposes from Schedule 1, financial statements or GIFI (line 300)	3,021,088
Part I tax payable (line 700)	
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, Speziale (Last name in block letters) Cindy (First name in block letters) Vice President - Finance (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part D to electronically file the corporation income tax return identified in Part A. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

Date (yyyy/mm/dd)	Signature of an authorized signing officer of the corporation	Telephone number
2012-04-20		(807) 343-1118

Part D – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part A.

Name of person or firm: BDO Canada LLP

Electronic filer number: A3065

Privacy Act, Personal Information Bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

EXEMPT FROM TAX

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, paragraphs, and subparagraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

055 **Do not use this area**

Identification

Business Number (BN) 001 89209 0614 RC0001

Corporation's name
002 Thunder Bay Hydro Electricity Distribution Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 34 N. Cumberland Street
012

City: 015 Thunder Bay
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 P7A 4L4

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023

City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

Location of books and records
Has the location of books and records changed since the last time we were notified . . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 34 N. Cumberland Street
032

City: 035 Thunder Bay
Province,territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 P7A 4L4

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 _____ YYYY MM DD

To which tax year does this return apply?
Tax year start 060 2011-01-01 YYYY MM DD
Tax year-end 061 2011-12-31 YYYY MM DD

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . . 065 _____ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with:
subparagraph 88(2)(a)(iv)? . . . . . 064 1 Yes [ ] 2 No [X]
subsection 249(3.1)? . . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [X] Exempt under other paragraphs of section 149

Do not use this area
095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Was the resident corporation the beneficiary of a non-resident discretionary trust or did it make a contribution to a non-resident discretionary trust at any time during the tax year?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricty Distribution	285	97.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes	2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300 3,021,088	A
Deduct: Charitable donations from Schedule 2	311	16,786		
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal		16,786 ▶	16,786	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			3,004,302	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360 3,004,302	
Income exempt under paragraph 149(1)(t)			370	
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** 3,021,088 A

Taxable income from line 360 on page 3, **minus** 10/3 of the amount on line 632* on page 7, **minus** 1/(0.38 - X**) 3.77358 times the amount on line 636*** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** B

Business limit (see notes 1 and 2 below) . . . . . **410** 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x **415** **** 212,657 / 11,250 D = ... 9,451,422 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** F

Small business deduction

Amount A, B, C, or F, whichever is the least x 17 % = ... **430** G

Enter amount G on line 1 on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** General rate reduction percentage for the tax year. It has to be pro-rated.

*** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

**** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3			A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	B		
Amount QQ from Part 13 of Schedule 27	C		
Amount used to calculate the credit union deduction from Schedule 17	D		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least	E		
Aggregate investment income from line 440 on page 6*	F		
Total of amounts B to F		▶	G
Amount A **minus** amount G (if negative, enter "0")			H

Amount H		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365	x	9 %	=	I
Amount H		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365	x	10 %	=	J
Amount H		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	K
Amount H		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365	x	13 %	=	L

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L M

Enter amount M on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27	O		
Amount QQ from Part 13 of Schedule 27	P		
Amount used to calculate the credit union deduction from Schedule 17	Q		
Total of amounts O to Q		▶	R
Amount N **minus** amount R (if negative, enter "0")			S

Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365	x	9 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	365	x	10 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	365	x	13 %	=	W

General tax reduction – Total of amounts T to W X

Enter amount X on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . . 440 _____ x 26 2 / 3 % = ... _____ A

Foreign non-business income tax credit from line 632 on page 7 . . . . . _____

Deduct:

Foreign investment income from Schedule 7 . . . . . 445 _____ x 9 1 / 3 % = _____
(if negative, enter "0") _____ ▶ _____ B

Amount A **minus** amount B (if negative, enter "0") . . . . . _____ C

Taxable income from line 360 on page 3 3,004,302

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . _____

Foreign non-business income tax credit from line 632 on page 7 . . . _____ x 25 / 9 = _____

Foreign business income tax credit from line 636 on page 7 . . . . . _____ x 1(0.38 - X*) / 3.77358 = _____
_____ ▶ _____
3,004,302
x 26 2 / 3 % = 801,147 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . . _____ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . . 450 _____ F

* General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . . 460 _____

Deduct: Dividend refund for the previous tax year . . . . . 465 _____
_____ ▶ _____ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . . _____

Total Part IV tax payable from Schedule 3 . . . . . _____

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . . 480 _____
_____ ▶ _____ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . . 485 _____

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . . _____ x 1 / 3 _____ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . . _____ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) . . . . . _____

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 % 550 _____ A

Recapture of investment tax credit from Schedule 31 . . . . . 602 _____ B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . . _____ i

Taxable income from line 360 on page 3 3,004,302

Deduct:

Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . . _____

Net amount . . . . . 3,004,302 ▶ 3,004,302 ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . 604 _____ C

Subtotal (**add** lines A to C) _____ D

Deduct:

Small business deduction from line 430 on page 4 . . . . . _____ 1

Federal tax abatement . . . . . 608 _____

Manufacturing and processing profits deduction from Schedule 27 . . . . . 616 _____

Investment corporation deduction . . . . . 620 _____

Taxed capital gains 624 _____

Additional deduction – credit unions from Schedule 17 . . . . . 628 _____

Federal foreign non-business income tax credit from Schedule 21 . . . . . 632 _____

Federal foreign business income tax credit from Schedule 21 . . . . . 636 _____

General tax reduction for CCPCs from amount M on page 5 . . . . . 638 _____

General tax reduction from amount X on page 5 . . . . . 639 _____

Federal logging tax credit from Schedule 21 . . . . . 640 _____

Federal qualifying environmental trust tax credit . . . . . 648 _____

Investment tax credit from Schedule 31 . . . . . 652 _____

Subtotal _____ ▶ _____ E

Part I tax payable – Line D **minus** line E . . . . . _____ F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765	
Total tax payable	770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from page 6	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 1 Overpayment

Balance (line A **minus** line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

Certification

I, 950 Speziale (Last name in block letters) 951 Cindy (First name in block letters) 954 Vice President - Finance (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-04-20 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (807) 343-1118 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☒ 2 No ☐

958 Name in block letters 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Privacy Act, Personal Information Bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	31,981,726	31,123,242
	Total tangible capital assets	2008	+	155,156,722	147,717,330
	Total accumulated amortization of tangible capital assets	2009	–	87,500,532	82,936,584
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	14,700,815	14,805,590
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	114,338,731	110,709,578
Liabilities					
	Total current liabilities	3139	+	17,012,570	16,881,234
	Total long-term liabilities	3450	+	49,946,241	48,478,815
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	66,958,811	65,360,049
Shareholder equity					
	Total shareholder equity (mandatory field)	3620	+	47,379,920	45,349,529
	Total liabilities and shareholder equity	3640	=	114,338,731	110,709,578
Retained earnings					
	Retained earnings/deficit – end (mandatory field)	3849	=	12,448,295	10,417,904

* Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

Income statement information

Description	GIFI

Operating name	0001	
Description of the operation	0002	
Sequence Number	0003	01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	103,377,657	95,171,784
	Cost of sales	8518	–	85,875,693	78,674,166
	Gross profit/loss	8519	=	17,501,964	16,497,618
	Cost of sales	8518	+	85,875,693	78,674,166
	Total operating expenses	9367	+	17,169,597	17,728,566
	Total expenses (mandatory field)	9368	=	103,045,290	96,402,732
	Total revenue (mandatory field)	8299	+	105,737,556	97,137,764
	Total expenses (mandatory field)	9368	–	103,045,290	96,402,732
	Net non-farming income	9369	=	2,692,266	735,032
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	2,692,266	735,032
	Total other comprehensive income	9998	=		
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	706,875	580,000
	Deferred income tax provision	9995	–	-45,000	-326,500
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	2,030,391	481,532

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SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation?	095	1 Yes	X	2 No	
Is the accountant connected* with the corporation?	097	1 Yes		2 No	X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: **198**

Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation?	099	1 Yes		2 No	X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: **110**

Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

Were notes to the financial statements prepared?	101	1 Yes	X	2 No	

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes?	104	1 Yes		2 No	X
Is re-evaluation of asset information mentioned in the notes?	105	1 Yes		2 No	X
Is contingent liability information mentioned in the notes?	106	1 Yes		2 No	X
Is information regarding commitments mentioned in the notes?	107	1 Yes	X	2 No	
Does the corporation have investments in joint venture(s) or partnership(s)?	108	1 Yes		2 No	X

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . . 250 1 Yes ☐ 2 No ☒

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes ☐ 2 No ☒

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes ☐ 2 No ☒

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes ☐ 2 No ☒

If **yes**, you have to maintain a separate reconciliation.

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				2,030,391 A
Add:				
Provision for income taxes – current		101	706,875	
Provision for income taxes – deferred		102	-45,000	
Amortization of tangible assets		104	5,032,895	
Charitable donations and gifts from Schedule 2		112	16,786	
Non-deductible meals and entertainment expenses		121	17,993	
Subtotal of additions			5,729,549 ▶	5,729,549
Other additions:				
Miscellaneous other additions:				
600 Smart Meter net revenues		290	1,067,020	
603 Ontario Specified Tax Credits	105,863			
Total	105,863	293	105,863	
604 Regulatory Asset Recovery	196,244			
Total	196,244	294	196,244	
Subtotal of other additions		199	1,369,127 ▶	1,369,127
Total additions		500	7,098,676 ▶	7,098,676
Deduct:				
Gain on disposal of assets per financial statements		401	25,451	
Capital cost allowance from Schedule 8		403	5,810,032	
Cumulative eligible capital deduction from Schedule 10		405	66,684	
Subtotal of deductions			5,902,167 ▶	5,902,167
Other deductions:				
Miscellaneous other deductions:				
700 IFRS Implementation Cost Deferrals		390	42,993	
701 Regulatory Asset Deductions		391	12,773	
704 ARO expenses	32,077			
Future Employee Benefits	117,969			
Total	150,046	394	150,046	
Subtotal of other deductions		499	205,812 ▶	205,812
Total deductions		510	6,107,979 ▶	6,107,979
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				3,021,088

T2 SCH 1 E (10)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 2

CHARITABLE DONATIONS AND GIFTS

Name of corporation	Business Number	Tax year-end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- For use by corporations to claim any of the following:
  - charitable donations;
  - gifts to Canada, a province, or a territory;
  - gifts of certified cultural property;
  - gifts of certified ecologically sensitive land; or
  - additional deduction for gifts of medicine.
- The donations and gifts are eligible for a five-year carryforward.
- Use this schedule to show a credit transfer following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the *Income Tax Act*.
- For donations and gifts made after March 22, 2004, subsection 110.1(1.2) of the *Income Tax Act* provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- Under proposed changes, the eligible amount of a charitable gift is the amount by which the fair market value of the gift exceeds the amount of an advantage, if any, for the gift.
- Under proposed changes, a gift of medicine made after March 18, 2007, to qualifying organizations for activities outside of Canada, may be eligible for an additional deduction if the gift is an eligible medical gift. This additional deduction is calculated in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation – Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
See list attached	16,786
Subtotal	16,786
Add: Total donations of less than $100 each	
Total donations in current tax year	16,786

		Federal	Québec	Alberta
Charitable donations at the end of the previous tax year				
Deduct: Charitable donations expired after five tax years*	239			
Charitable donations at the beginning of the tax year	240			
Add:				
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250			
Total current-year charitable donations made (enter this amount on line 112 of Schedule 1) 210 16,786				
Subtotal (line 250 **plus** line 210)		16,786	16,786	16,786
Deduct: Adjustment for an acquisition of control (for donations made after March 22, 2004)	255			
Total charitable donations available		16,786 A	16,786	16,786
Deduct: Amount applied against taxable income (cannot be more than amount K in Part 2) (enter this amount on line 311 of the T2 return)	260	16,786	16,786	16,786
Charitable donations closing balance	280			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2000-12-31			
12th prior year	1999-12-31			
13th prior year	1998-12-31			
14th prior year	1997-12-31			
15th prior year	1996-12-31			
16th prior year	1995-12-31			
17th prior year	1994-12-31			
18th prior year	1993-12-31			
19th prior year	1992-12-31			
20th prior year	1991-12-31			
21st prior year*	1990-12-31			
Total (to line A)				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 % ..... 2,265,816 B

Taxable capital gains arising in respect of gifts of capital property included in Part 1** ..... 225 _____ C

Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01) ..... 227 _____ D

The amount of the recapture of capital cost allowance in respect of charitable gifts ..... 230 _____

Proceeds of disposition, less outlays and expenses** ..... _____ E

Capital cost** ..... _____ F

Amount E or F, whichever is less ..... 235 _____

Amount on line 230 or 235, whichever is less ..... _____ G

Subtotal (**add** amounts C, D, and G) _____ H

Amount H **multiplied** by 25 % _____ I

Subtotal (amount B **plus** amount I) 2,265,816 J

Maximum allowable deduction for charitable donations (enter amount A from Part 1, amount J, or net income for tax purposes, whichever is less) ..... 16,786 K

* For credit unions, this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year			
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339		
Gifts to Canada, a province, or a territory at the beginning of the tax year	340		▶
Add: Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350		
Total current-year gifts made to Canada, a province, or a territory*	310		
Subtotal (line 350 **plus** line 310)			
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	355		
Total gifts to Canada, a province, or a territory available			
Deduct: Amount applied against taxable income (enter this amount on line 312 of the T2 return).	360		
Gifts to Canada, a province, or a territory closing balance	380		

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

		Federal	Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year				
Deduct: Gifts of certified cultural property expired after five tax years*	439			
Gifts of certified cultural property at the beginning of the tax year	440			
Add: Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450			
Total current-year gifts of certified cultural property	410			
Subtotal (line 450 **plus** line 410)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	455			
Total gifts of certified cultural property available				
Deduct: Amount applied against taxable income (enter this amount on line 313 of the T2 return)	460			
Gifts of certified cultural property closing balance	480			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2000-12-31			
12th prior year	1999-12-31			
13th prior year	1998-12-31			
14th prior year	1997-12-31			
15th prior year	1996-12-31			
16th prior year	1995-12-31			
17th prior year	1994-12-31			
18th prior year	1993-12-31			
19th prior year	1992-12-31			
20th prior year	1991-12-31			
21st prior year*	1990-12-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

		Federal	Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year				
Deduct: Gifts of certified ecologically sensitive land expired after five tax years*	539			
Gifts of certified ecologically sensitive land at the beginning of the tax year	540			
Add: Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550			
Total current-year gifts of certified ecologically sensitive land	510			
Subtotal (line 550 **plus** line 510)				
Deduct: Adjustment for an acquisition of control (for gifts made after March 22, 2004)	555			
Total gifts of certified ecologically sensitive land available				
Deduct: Amount applied against taxable income (enter this amount on line 314 of the T2 return)	560			
Gifts of certified ecologically sensitive land closing balance	580			

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
7th prior year	2004-12-31			
8th prior year	2003-12-31			
9th prior year	2002-12-31			
10th prior year	2001-12-31			
11th prior year	2000-12-31			
12th prior year	1999-12-31			
13th prior year	1998-12-31			
14th prior year	1997-12-31			
15th prior year	1996-12-31			
16th prior year	1995-12-31			
17th prior year	1994-12-31			
18th prior year	1993-12-31			
19th prior year	1992-12-31			
20th prior year	1991-12-31			
21st prior year*	1990-12-31			
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 6 – Additional deduction for gifts of medicine

		Federal	Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year				
Deduct: Additional deduction for gifts of medicine expired after five tax years	639			
Additional deduction for gifts of medicine at the beginning of the tax year	640			
Add: Additional deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650			
Additional deduction for gifts of medicine for the current year:				
Proceeds of disposition	602	1	1	1
Cost of gifts of medicine	601	2	2	2
Subtotal (line 1 **minus** line 2)		3	3	3
Line 3 **multiplied** by 50 %		4	4	4
Eligible amount of gifts	600	5	5	5

Federal: A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year **610** _____

Québec: A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

Alberta: A _____ x (B _____ / C) = Additional deduction for gifts of medicine for the current year _____

where:

A is the **lesser** of line 2 and line 4

B is the eligible amount of gifts (line 600)

C is the proceeds of disposition (line 602)

		Federal	Québec	Alberta
Subtotal (line 650 **plus** line 610)				
Deduct: Adjustment for an acquisition of control	655			
Total additional deduction for gifts of medicine available				
Deduct: Amount applied against taxable income (enter this amount on line 315 of the T2 return)	660			
Additional deduction for gifts of medicine closing balance	680			

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2010-12-31			
2nd prior year	2009-12-31			
3rd prior year	2008-12-31			
4th prior year	2007-12-31			
5th prior year	2006-12-31			
6th prior year*	2005-12-31			
Total				

* These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2010-12-31	
2nd prior year	2009-12-31	
3rd prior year	2008-12-31	
4th prior year	2007-12-31	
5th prior year	2006-12-31	
6th prior year*	2005-12-31	
7th prior year	2004-12-31	
8th prior year	2003-12-31	
9th prior year	2002-12-31	
10th prior year	2001-12-31	
11th prior year	2000-12-31	
12th prior year	1999-12-31	
13th prior year	1998-12-31	
14th prior year	1997-12-31	
15th prior year	1996-12-31	
16th prior year	1995-12-31	
17th prior year	1994-12-31	
18th prior year	1993-12-31	
19th prior year	1992-12-31	
20th prior year	1991-12-31	
21st prior year*	1990-12-31	
Total		

* These gifts expired in the current year.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	10	Rolling Stock/Comp	1,566,738	399,566		20,000	189,783	1,756,521	30	0	0	526,956	1,419,348
2.	8	Office/Other Equip	791,971	176,603		7,075	84,764	876,735	20	0	0	175,347	786,152
3.	4	Building	1,669,542			0		1,669,542	6	0	0	100,173	1,569,369
4.	47	Distribution Equipment Post Feb	28,845,078	6,137,292	-322,110	0	3,068,646	31,591,614	8	0	0	2,527,329	32,132,931
5.	45	Computer Equipment acquired af	13,651			0		13,651	45	0	0	6,143	7,508
6.	1	Distribution Equipment	52,100,366			0		52,100,366	4	0	0	2,084,015	50,016,351
7.	50	Computer Equip Sub to Mar 18, :	38,451	99,528		0	49,764	88,215	55	0	0	48,518	89,461
8.	13	Leasehold Improvements		2,473		0	1,237	1,236	NA	0	0	247	2,226
9.	12	Application Software		38,388		0	19,194	19,194	100	0	0	19,194	19,194
10.	52	Computer Hardware/Software			322,110	0		322,110	100	0	0	322,110	
		Totals	85,025,797	6,853,850		27,075	3,413,388	88,439,184				5,810,032	86,042,540

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Thunder Bay Hydro Corporation		86523 2995 RC0001	1	1,000	100.000			34,931,625
2.	Thunder Bay Renewable Power Inc		86170 7461 RC0001	3					
3.	Thunder Bay Hydro Utility Services I		86189 1059 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 952,626 A

Add:

Cost of eligible capital property acquired during the taxation year . . . . . **222** _____

Other adjustments . . . . . **226** _____

Subtotal (line 222 plus line 226) _____ × 3 / 4 = _____ B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** _____ × 1 / 2 = _____ C

amount B minus amount C (if negative, enter "0") _____ ▶ _____ D

Amount transferred on amalgamation or wind-up of subsidiary . . . . . **224** _____ E

Subtotal (add amounts A, D, and E) **230** 952,626 F

Deduct:

Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . . **242** _____ G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** _____ H

Other adjustments . . . . . **246** _____ I

(add amounts G,H, and I) _____ × 3 / 4 = **248** _____ J

Cumulative eligible capital balance (amount F minus amount J) . . . . . 952,626 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business . . . . . **249** _____

amount K 952,626

less amount from line 249 _____

Current year deduction . . . . . 952,626 × 7.00 % = **250** 66,684 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 66,684 ▶ 66,684 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 885,942 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)					N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400	1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401	2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4			
Line 3 minus line 4 (if negative, enter "0")			▶	5	
Total of lines 1, 2 and 5				6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8			
Subtotal (line 7 plus line 8)	409		▶	9	
Line 6 minus line 9 (if negative, enter "0")				▶	O
Line N minus line O (if negative, enter "0")					P
Line 5 × 1 / 2 =					Q
Line P minus line Q (if negative, enter "0")					R
Amount R × 2 / 3 =					S
Amount N or amount O, whichever is less					T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)			410		

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)

2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction

3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)

4 – Associated non-CCPC

5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . 025 Year Month Day

Enter the calendar year to which the agreement applies . . . . . 050 Year 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . 075 1 Yes ☐ 2 No ☒

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Association code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	1	500,000	100.0000	500,000
2	Thunder Bay Hydro Corporation	86523 2995 RC0001	1	500,000		
3	Thunder Bay Renewable Power Incorporated	86170 7461 RC0001	1	500,000		
4	Thunder Bay Hydro Utility Services Inc.	86189 1059 RC0001	1	500,000		
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Thunder Bay Hydro Electricity Distribution Inc.	89209 0614 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	Thunder Bay Hydro Corporation	86523 2995 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Appendix 4-E

2009-2011 Notice of Assessments

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Keep this portion for your records.

Notice of Assessment

Electricity Act, 1998 • Corporations Tax Act, R.S.O. 1990
from 2009/01/01 **to** 2009/12/31

	Account No.	Assessment Date (year, month, day)	Page
THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	**1800284**	2010/08/09	1 of 1

ASSESSMENT NO. 228

Tax: Federal and Provincial PIL		932,172.00
Assessment Interest		816.20
Total Assessment Liability		932,988.20

SUMMARY OF 2009/12/31 TAXATION YEAR TRANSACTIONS

Payments/Transfers	1,026,412.00CR	
Sub-Total		1,026,412.00CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		93,423.80CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

PX5003 004

Tax (Re)Assessment Enquiries: • 1 866 ONT-TAXS (1 866 668-8297) ext. 21113 • FAX 416 218-3276 • TTY 1 800 263-7776 • ontario.ca/revenue

Account Billing Enquiries & Change of Address Information: • 1 866 ONT-TAXS (1 866 668-8297) • FAX 905 433-5197

Ontario

Ministry of Revenue
33 King St W
PO Box 622
Oshawa ON L1H 8H6

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HPL - tL059

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION
ATTENTION: C/O CINDY SPEZIALE
34 NORTH CUMBERLAND ST
THUNDER BAY ON P7A 4L4

0000188

Issue Date	22-Sep-2011
Identification No.	1800284
Reference No.	L0271891840

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2010	**Return As Filed**
Total Federal Tax	$396,980.00
Total Ontario Tax	$343,044.00
Total Credits	($102,630.00)
Loss Carry-back	$0.00
Total Tax Payable	$637,394.00
Interest	$0.00
Current Penalty	$0.00
Credits/Payments	($637,394.00)
Total Assessment	**$0.00**

As of 22-Sep-2011, including the amount assessed above, you have an overall credit balance on your account of ($279,250.00).

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Tax Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Revenue at the number listed below.

Ministry use only

Enquiries	1 866 ONT-TAXS 1 866 668-8297	Fax 1 866 888-3850	Teletypewriter (TTY) Internet	1 800 263-7776 **ontario.ca/revenue**

Ontario

Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

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HPL - IL059

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION
ATTENTION: C/O CINDY SPEZIALE
34 NORTH CUMBERLAND ST
THUNDER BAY ON P7A 4L4

0000019 6

Issue Date	09-Jul-2012
Business No.	892090614TW0001
Reference No.	L1303553920

Notice of Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

Your account has been assessed resulting in a balance as indicated below.

Period Ending: 31-Dec-2011	**Return As Filed**
Total Federal Tax	$495,710.00
Total Ontario Tax	$316,704.00
Total Credits	($105,863.00)
Loss Carry-back	$0.00
Total Tax Payable	$706,551.00
Interest	$0.00
Current Penalty	$0.00
Credits/Payments	($706,551.00)
Total Assessment	**$0.00**

As of 09-Jul-2012, including the amount assessed above, you have an overall credit balance on your account of ($293,477.00).

If you have any questions concerning this Notice of Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

Ministry use only

Enquiries	1 866 ONT-TAXS 1 866 668-8297	Fax 1 866 888-3850	Teletypewriter (TTY) Internet	1 800 263-7776 **ontario.ca/finance**

1

Exhibit	Tab	Schedule	Appendix	Contents
5 – Cost of Capital and Rate of Return				
	1	1		Overview
		2		Capital Structure
			5-A	Promissory Note

OVERVIEW

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2013 Test Year.

Capital Structure

Thunder Bay Hydro has a current deemed capital structure of 4% short term debt with a return of 1.33%, 56% long-term debt with a return of 0.21%, and 40% equity with a return of 3.75% as approved in the 2009 rate decision (EB-2008-0245).

Thunder Bay Hydro has prepared this rate application with a deemed capital structure of 56% Long Term Debt with a return of 1.89%, 4% Short Term Debt with a return of 2.08%, and 40% Equity with a return of 7%. The rates vary from the most recent updated Cost of Capital Parameters issued by the OEB (March 2, 2012 letter to all LDCs Re: The Cost of Capital Parameter Updates for 2012 Cost of Service Application for Rate Effective May 1, 2012) as explained in the following paragraph.

Return on Equity

Thunder Bay Hydro is requesting a return on equity ("ROE") for the 2013 Test Year of 7% in accordance with the shareholder direction for rate minimization. It is acknowledged that this is still well below the maximum allowed for rate of return on equity of 9.12% approved for the 2012 cost of service rate applications and should be well below the maximum allowed rate of return on equity approved for the 2013 cost of service rate applications. This is a savings of approximately $800,455 calculated as the difference in the maximum rate of return of 9.12% and Thunder Bay Hydro's rate of return on equity of 7% times 40% of Thunder Bay Hydro's rate base of $94,393,281. As was the case at the time of filing our 2009 cost of service application, Thunder Bay Hydro's shareholder does not require dividend payments, allowing Thunder Bay Hydro to limit increase in rates sufficient to fund capital and operating needs while continuing to comply with existing debt covenants. Thunder Bay Hydro understands that the OEB will be finalizing the ROE for 2013 rates based on January 2013 market interest rate information. Thunder Bay Hydro's use of an ROE of 7% is without prejudice to any revised ROE that may be adopted by the OEB in early 2013.

COST OF DEBT

Long Term Debt

Thunder Bay Hydro is requesting a return on Long Term Debt for the 2013 Test Year of 1.89%. Thunder Bay Hydro currently has two debt instruments, (1) a promissory note payable to the Corporation of the City of Thunder Bay paying 0% (**see Appendix 5-A**) and a loan bearing interest at 5.27% that was taken out in July of 2009 to fund the Smart Meter Initiative. The loan for the Smart Meter Initiative was awarded to the successful proponent of the competitive bid process (Request for Proposal) and is in compliance with the 2009 Report. This cost of service application now reflects all of the assets/liabilities/expenses relating to the government mandated Smart Meter program. Thunder Bay Hydro has issued a Request for Proposal -RFP #P12-54 (RFP) for a five year financing agreement with the first loan draw to occur in the fall of 2012. Given that Thunder Bay Hydro has yet to make an award (all third party proponents) and as such does not have an actual interest rate as of the date of writing this application, Thunder Bay Hydro has used the OEB Board approved Deemed Long-Term Debt rate of 4.41% for the 2012 and expected 2013 financing.

The 2012 and 2013 financing is not tied to specific capital projects, but rather is based on the annual projected spend in excess of Thunder Bay Hydro's "Rate Minimization" calculation. Thunder Bay Hydro's forecasted capital expenditures and financing is detailed in Table 5-1.1 below.

Table 5-1.1 - Thunder Bay Hydro's forecasted capital expenditures and financing

YEAR	Infrastructure Replacement	Growth/Externally Driven Capital Plan Net of Capital Contributions	Tangible Equipment Purchases (Computer, Furniture, Equipment, Tools and Rolling Stock)	Total Capital Expenditures CGAAP	Internally Financed	External Financing Required	Total Capital Expenditures (MCGAAP)	Internally Financed	External Financing Required
2012					34.41%	65.59%		34.41%	65.59%
	6,812,737	***1,051,283***	***978,454***	***8,842,474***	***3,042,474***	***5,800,000***	***8,842,474***	***3,042,474***	***5,800,000***
2013**					54.07%	45.93%		49.31%	50.69%
	7,726,530	***989,613***	***4,673,491***	***13,389,634***	***7,239,634***	***6,150,000***	***12,132,192***	***5,982,192***	***6,150,000***
2014					51.80%	48.20%		45.16%	54.84%
	8,948,852	***1,009,405***	***1,400,961***	***11,359,218***	***5,884,218***	***5,475,000***	***9,983,350***	***4,508,350***	***5,475,000***
2015					51.75%	48.25%		45.61%	54.39%
	9,976,796	***1,029,593***	***1,428,980***	***12,435,369***	***6,435,369***	***6,000,000***	***11,031,983***	***5,031,983***	***6,000,000***
2016					44.65%	55.35%		38.11%	61.89%

***** 2013 Tangible Capital include $3.3M for New Maintenance Facility***

In addition to the forecasted financing for the Bridge and Test Year, Thunder Bay Hydro has included what has been termed "Annualization Debt" at the OEB Board approved rate of 4.41%. As noted in previous parts of this application, Thunder Bay Hydro operates under the "rate minimization model". This is defined in our Shareholder Declaration as follows:

> *Rate Minimization Model* means a Shareholder philosophy of minimizing electricity rates for customers of DistributionCo by having these rates reflect the Shareholder forgoing its allowable regulated return on shareholder equity from DistributionCo and forgoing payment of interest or principal on long term debt held in DistributionCo by the Shareholder.

Given this uniqueness about Thunder Bay Hydro, we have deviated from Chapter 2 of the OEB Filing guidelines in two ways: (1) the interest calculation for the 2013 financing has not been prorated based on the expected draw date and (2) an "annualization debt" amount has been included in Thunder Bay Hydro's debt structure (Table 5-1.2 below). The "annualization debt" amount is sufficient to bring the deemed interest amount funded in rates to the average interest cost on external financing requirements during the IRM period to the next cost of service rebasing (four years) Thunder Bay Hydro's forecasted interest on long term debt over the next four years is shown in Table 5-1.3 below.

Table 5-1.2 - Interest Projected 2013-2016

Table INTEREST PROJECTED 2013-2016

	Interest Projected	Funded in Rate Base	Under(over) funded	PILS Cost (Savings)
2013	662,777	1,001,585	$ (338,808)	$ 89,784
2014	896,560	1,001,585	$ (105,025)	$ 27,832
2015	1,105,822	1,001,585	$ 104,237	$ (27,623)
2016	1,341,181	1,001,585	$ 339,596	$ (89,993)
Average annual interest	1,001,585	1,001,585	0	$ 0

Table 5-1.3 provides Thunder Bay Hydro's debt and capital structure.

Table 5-1.3 - Thunder Bay Hydro's debt and capital structure

DEBT AND CAPITAL COST STRUCTURE
Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Promissory Note	The Corporation of the City of Thunder Bay**	Y	Sept. 1, 2001	31,452,941		0.00%	2001	0
2012 Infrastructure Financing	Unknown	N	Oct. 1, 2012	5,800,000	25	4.41%	2012	255,780
2013 Infrastructure Financing	Unknown	N	Jan. 1, 2013	6,150,000	25	4.41%	2013	271,215
Smart Meter Financing in Rate Base	TD Commercial Bank	N	Jan. 1, 2012	6,688,761	15	5.27%	2013	352,498
Annualization of Projected Debt over the rebasing period	N/A	N	Jan. 1, 2013	2,768,526	25	4.41%	2013	122,092
			2013 Total Long Term Debt	52,860,228		**Total Interest Cost for 2013**		1,001,585
						Weighted Debt Cost Rate for 2013		1.89%

**The Promissory Note for the City of Thunder Bay will be updated to reflect conversion of a portion of the debt to equity.

As documented in the Asset Management Program, Thunder Bay Hydro will be continuing to increment its investment in infrastructure replacement above the capital contributions,

depreciation and net income reinvestment level. The net income for reinvestment is declining as financing is obtained, resulting in a larger percentage of the capital assets to be externally financed. Thunder Bay Hydro has utilized existing work capital to the maximum extent possible to fund the increased level of capital expenditures to date. The working capital allowance after reducing cash by the amount owed to Thunder Bay Hydro customers for the net regulatory liabilities as at December 31, 2013 is approaching the OEB rate of 13% as shown in Table 5-1.4 below:

Table 5-1.4 - Working Capital Review

Working Capital Review		Dec-13
Cash, December 31, 2013	$	10,469,041
Less Distribution Revenue**	$	(519,778)
Less Regulatory Accounts	$	(3,744,220)
	$	6,205,043
Current Assets less Cash	$	23,911,033
	$	30,116,076
Current Liabilities	$	15,151,488
Working Capital	$	14,964,588
Working Capital Allowance	$	14,487,107

**Distribution revenue permanently four months in arrears.

Thunder Bay Hydro feels that this deviation from the guidelines is necessary to ensure funding is available to service the new debt. Thunder Bay Hydro must ensure that it can continue to meet debt covenants in the IRM years.

Short Term Debt

Thunder Bay Hydro is requesting a return on Short Term Debt for the 2013 Test Year of 2.08% in accordance with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications issued by the OEB on March 3, 2012. Thunder Bay Hydro understands that the OEB will be finalizing the return on short term debt for 2013 rates based on January 2013 market interest rate information. Thunder Bay Hydro's use of a Return on Short Term Debt of 2.08% is without prejudice to any revised Short Term Debt rate that may be adopted by the OEB in early 2013.

Rate Base and Rate of Return

Table 5.1.2 of Exhibit 5, Tab 1, Schedule 1 details Thunder Bay Hydro's rate base, deemed debt/equity ratios, deemed rate of return, actual debt/equity ratios and actual rates of returns for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, and 2012 Bridge and 2013 Test Year Forecast.

CAPITAL STRUCTURE

Table 5-2.1 – Deemed Capital Structure 2009 to 2013

Appendix 2-OA
Capital Structure and Cost of Capital
2009

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	52.70%	$38,998,630	0.00%	$ -
2	Short-term Debt	4.00% (1)	$2,960,048	1.33%	$39,369
3	**Total Debt**	56.7%	$41,958,678	0.09%	$39,369
	Equity				
4	Common Equity	43.30%	$32,042,518	3.75%	$1,201,594
5	Preferred Shares		$ -		$ -
6	**Total Equity**	43.3%	$32,042,518	3.75%	$1,201,594
7	**Total**	100.0%	$74,001,196	1.68%	$1,240,963

Notes
(1) 4.0% unless an applicant has proposed or been approved for a different amount.

Capital Structure and Cost of Capital
2010

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$42,351,109	0.00%	$ -
2	Short-term Debt	4.00% (1)	$3,025,079	1.33%	$40,234
3	**Total Debt**	60.0%	$45,376,188	0.09%	$40,234
	Equity				
4	Common Equity	40.00%	$30,250,792	3.75%	$1,134,405
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$30,250,792	3.75%	$1,134,405
7	**Total**	100.0%	$75,626,981	1.55%	$1,174,638

Capital Structure and Cost of Capital

2011

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$43,864,608	0.00%	$ -
2	Short-term Debt	4.00% (1)	$3,133,186	1.33%	$41,671
3	**Total Debt**	60.0%	$46,997,794	0.09%	$41,671
	Equity				
4	Common Equity	40.00%	$31,331,863	3.75%	$1,174,945
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$31,331,863	3.75%	$1,174,945
7	**Total**	100.0%	$78,329,656	1.55%	$1,216,616

Capital Structure and Cost of Capital

2012

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$48,510,483	0.69%	$333,075
2	Short-term Debt	4.00% (1)	$3,465,034	1.33%	$46,085
3	**Total Debt**	60.0%	$51,975,517	0.73%	$379,160
	Equity				
4	Common Equity	40.00%	$34,650,345	3.75%	$1,299,388
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$34,650,345	3.75%	$1,299,388
7	**Total**	100.0%	$86,625,862	1.94%	$1,678,548

Capital Structure and Cost of Capital

2013

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$52,860,237	1.89%	$1,001,585
2	Short-term Debt	4.00% (1)	$3,775,731	2.08%	$78,535
3	**Total Debt**	60.0%	$56,635,968	1.91%	$1,080,120
	Equity				
4	Common Equity	40.00%	$37,757,312	7.00%	$2,643,012
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$37,757,312	7.00%	$2,643,012
7	**Total**	100.0%	$94,393,281	3.94%	$3,723,132

APPENDICES

APPENDIX 5-A
PROMISSORY NOTE

DEMAND PROMISSORY NOTE

CDN $33,490,500 **Thunder Bay, Ontario**

Note Date: July 21, 2005

FOR VALUE RECEIVED, the undersigned, THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC., a corporation existing under the laws of the Province of Ontario (the "**Promisor**"), hereby promises to pay to or to the order of THE CORPORATION OF THE CITY OF THUNDER BAY (the "**Holder**") the principal amount of THIRTY-THREE MILLION FOUR HUNDRED AND NINETY THOUSAND FIVE HUNDRED DOLLARS (CDN $33,490,500) (the "**Principal Amount**") in lawful money of Canada on the following terms:

1. The Promisor shall repay the Principal Amount to the Holder on demand.
2. The Promisor shall not pay any interest to the Holder in connection with the Principal Amount hereunder.
3. The Promisor shall have the right to prepay at any time the Principal Amount, in whole or in part, without notice, bonus or penalty.
4. The Promisor hereby waives diligence, presentment, demand, protest, notice of any kind whatsoever and any other condition precedent to action against the Promisor for the repayment of this Promissory Note.
5. If the Promisor is required by law to make any deduction or withholding from any payment hereunder, it shall do so and the amount due from the Promisor in respect of such payment shall be increased to the extent necessary to ensure that, after making such deduction or withholding, the Holder receives a net amount equal to the amount it would have received had no deduction or withholding been required to be made. The Promisor shall promptly notify the Holder if at any time either Promisor is required by law to make any such deduction or withholding.
6. No change, modification, alteration or rescission of any terms of this Promissory Note shall be binding on the Holder or the Promisor unless made in writing and signed by both of them.
7. This Promissory Note shall be binding upon and enure to the benefit of the Promisor and the Holder and their respective successors and permitted assigns. This Promissory Note and the rights and obligations hereunder may not be assigned by the Promisor except with the written consent of the Holder.
8. This Promissory Note shall be governed by and construed in accordance with the laws of the Province of Ontario.

IN WITNESS WHEREOF the Promisor has caused this Promissory Note to be executed on the date noted above.

THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.

By: _____
Name: Robert Mace, MBA
Title: President

By: _____
Name: C. Thomas Wright, CA
Title: Treasurer

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Exhibit	Tab	Schedule	Appendix	Contents
6 – Calculation of Revenue Deficiency or Surplus				
	1	1		Revenue Deficiency - Overview
		2		Cost Drivers for Revenue Deficiency

REVENUE DEFICIENCY - OVERVIEW

Thunder Bay Hydro's revenue deficiency is $1,559,334.

This deficiency is calculated as the difference between the 2013 Test Year Revenue Requirement of $21,652,791 and the Forecast 2013 Test Year Revenue, based on the 2012 approved rates, at $20,093,456.

Table 6-1.1 on the following page provides the revenue deficiency calculations.

Revenue Requirement

Thunder Bay Hydro's Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expense
- Operation & Maintenance Expense
- Depreciation Expense
- PILs
- Deemed Interest & Return on Equity

Thunder Bay Hydro's revenue requirement is primarily received through electricity distribution rates and offset by revenue from OEB-approved specific service charges, late payment charges, interest, and other operating income.

Table 6-1.1: Calculation of Revenue Deficiency (MCGAAP)

Thunder Bay Hydro Electricity Distribution Inc. Revenue Deficiency Determination			
Description	**2012 Bridge Actual**	**2013 Test Existing Rates**	**2013 Test - Required Revenue**
Revenue			
Revenue Deficiency			**1,559,334**
Distribution Revenue	21,217,869	18,341,720	18,341,720
Other Operating Revenue (Net)	1,210,942	1,751,736	1,751,736
Total Revenue	**22,428,811**	**20,093,456**	**21,652,791**
Costs and Expenses			
Administrative & General, Billing & Collecting	6,825,827	7,146,549	7,146,549
Operation & Maintenance	6,943,137	7,511,666	7,511,666
Depreciation & Amortization	6,860,539	3,247,244	3,247,244
Charitable Donation (LEAP)	-	24,200	24,200
Deemed Interest	379,160	1,080,120	1,080,120
Total Costs and Expenses	**21,008,662**	**19,009,779**	**19,009,779**
Utility Income Before Income Taxes	**1,420,149**	**1,083,677**	**2,643,012**
Income Taxes:			
Corporate Income Taxes	375,757	-	-
Total Income Taxes	**375,757**	**0**	**0**
Utility Net Income	**1,044,391**	**1,083,677**	**2,643,012**
Income Tax Expense Calculation:			
Accounting Income	1,420,149	1,083,677	2,643,012
Tax Adjustments to Accounting Income	601,578	(2,831,251)	(2,831,251)
Taxable Income	**2,021,726**	(1,747,574)	(188,239)
Income Tax Before Tax Credits	**535,757**	**0**	0
Tax Credits	**160,000**	**0**	**0**
Income Tax Expense	375,757	0	0
Tax Rate Refecting Tax Credits	26.50%	0.00%	0.00%
Actual Return on Rate Base:			
Rate Base	86,625,862	94,393,281	94,393,281
Interest Expense	379,160	1,080,120	1,080,120
Net Income	1,044,391	1,083,677	2,643,012
Total Actual Return on Rate Base	**1,423,551**	**2,163,797**	**3,723,132**
Actual Return on Rate Base	1.64%	2.29%	3.94%
Required Return on Rate Base:			
Rate Base	86,625,862	94,393,281	94,393,281
Return Rates:			
Return on Debt (Weighted)	0.73%	1.91%	1.91%
Return on Equity	3.75%	7.00%	7.00%
Deemed Interest Expense	379,160	1,080,120	1,080,120
Return On Equity	1,299,388	2,643,012	2,643,012
Total Return	**1,678,548**	**3,723,132**	**3,723,132**
Expected Return on Rate Base	1.94%	3.94%	3.94%
Revenue Deficiency After Tax	**254,997**	**1,559,334**	**0**
Revenue Deficiency Before Tax	**346,934**	**1,559,334**	**0**

COST DRIVERS ON REVENUE DEFICIENCY

The Applicant notes there are several factors that contribute to the gross revenue deficiency of $1,559,334 for the 2013 Test Year. The following discussion highlights some significant items that contribute to this deficiency.

Operating Expenses

Thunder Bay Hydro's OM&A expenses have increased $2,774,169 from the 2009 approved amount of $11,644,677 to $14,418,846 in the 2013 Test Year. In light of the results of the OEB led Kinetrics Depreciation Report and required changes in preparation for the transition to Modified International Financial Reporting Standards (MIFRS) in 2014 Thunder Bay Hydro has made changes to its capitalization and depreciation policies in 2013 in order to be compliant with the new standards. Under "Modified" CGAAP (MCGAAP), $1,264,420 of expenses, the majority of which represent costs that Thunder Bay Hydro previously capitalized as part of its burdens, will no longer be capitalized. The full details of this change are outlined in Exhibit 4, Tab 4. The remaining cost increase of $1,509,749 is explained as follows:

- Approximately $326,000 incremental costs related to the Government's Smart Meter Initiative which effective January 1, 2012 are included in rate base;

- Increased labour costs of approximately $230,000, representing an increase of 5% over the 2009 Board Approved COS application. The increases are a result of increased complement of I FTE in the Finance Staff (Business & Regulatory Analyst); apprentice complement increase for succession planning and wage progressions and the following union contract negotiation and management increases as shown in Table 6-1.2.

Table 6-1.2 – Union Contract Negotiation and Management Increases

Contract Period	Rate for Outside Staff*	Rate for Inside Staff*	Management*
May 1, 2009-April 30, 2010	4.0% or 2%	3.5% or 2%	3% or 2.3%
May 1, 2010-April 30, 2011	3.0% or 1.5%	3.0% or 1.5%	3.0%
May 1, 2011-April 30, 2012	3.0% or 1.5%	3.0% or 1.5%	3.0%
May 1, 2012-April 30, 2013	3.0% or 1.5%	3.0% or 1.5%	3.0%
*The rates vary accordingly to employee groups.			

(See discussion at Exhibit 4, Tab 2, Schedule 4, page 3);

- approximately $154,000 increase in benefits, most notably the OMERs pension cost which increases $45,000 from 2012 alone;

- approximately $280,000 in overtime costs (Thunder Bay Hydro is continually reviewing overtime requirements with the objective of reducing such and the 2013 Test Year is approximately $26,000 below the five year historical overtime average as shown below in Table 6-1.3);

Table 6-1.3 – Overtime Costs

Overtime							
2007 Actuals	2008 Actuals	BA2009	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
$414,416	$ 346,802	$ 93,195	$ 397,537	$ 433,779	$ 408,494	$ 417,482	$ 373,985
Average of the 2007-2011 Actual Overtime					**$400,205**		

- Approximately $198,500 increased I.T. Department Costs ($127,000 is labour, overtime and benefits -$75,000 of which was a market adjustment to labour costs in 2009) and the remaining is an increase in hardware and software maintenance agreements and subscriptions reflective of required new hardware/software acquisitions. The most significant of these agreements and subscriptions relate to new servers, storage area networks, media library hardware as well as new communication and document management software systems;

- Approximately $80,000 increase in the Forestry Management outside service costs. This is in keeping with our Asset Management Plan which commenced with the 2009 COS application;

- The balance of the increase $241,249 is a number of drivers under the materiality threshold of $85,000.

See also Exhibit 4, Tab 2, Schedule 3 for the cost driver review.

Depreciation Expense

Depreciation expense has reduced by $1,223,318 since the last rebasing in 2009. Included in this amount is an increase as a result of the normal annual increase in property, plant and equipment, approximately $600,000 increase due to the smart meter assets inclusion in Rate Base offset by a reduction due to the change to MCGAAP of $2,440,000.

PILs

PILs have reduced by $876,000 since the last rebasing in 2009. Thunder Bay Hydro is not including an amount for PILs in this application. The change in depreciation and OM&A expenses as a result of Thunder Bay Hydro's change in the depreciation and capitalization policy (MCGAAP) to align with the coming IFRS Standards have reduced taxable income such that no PILs funding is necessary. Thunder Bay Hydro's tax adjustment for depreciation is significantly lower than the capital cost allowance deduction resulting in a negative taxable income. Canada Revenue Agency relies on "generally accepted accounting principles" (GAAP) and in light of the coming IFRS Standards changing the Canadian GAAP, Canada Revenue Agency may adjust the capital cost allowance rate on distribution assets (currently at 8% from 4% in 2005) to more appropriately align. Additionally, Thunder Bay Hydro has the ability to reduce the CCA claim in any year such that taxable income is nil (if such is deemed to be appropriate). PILs funding included in distribution rates in the 2009 COS was $876,000.

Deemed Interest and Return on Equity

Thunder Bay Hydro's deemed interest on long-term debt has increased $883,611 after adjusting the 2009 COS capital parameter from 52.7% to 56%. Thunder Bay Hydro has existing debt and is currently in the process of securing a financing agreement for the next five years ending December 31, 2016. As discussed in Exhibit 5, the interest on long-term debt has been recorded at $1,001,585 which is the annualized amount based on the forecasted debt load for 2012 to 2016. Thunder Bay Hydro has increased the rate of return on equity from 3.75% to 7% which has increased the Revenue Requirement by $1,323,067 after adjusting the 2009 COS capital parameter from 43.3% to 40%. As mentioned throughout this application, Thunder Bay Hydro operates on the "Rate Minimization" model and does not earn a return for purposes of shareholder dividends or debt servicing. As Thunder Bay Hydro's investment in property, plant and equipment has increased above the annual depreciation and net income amount, cash flow (net of the regulatory liabilities) has been considerably reduced such that external financing to fund the capital investment is and will continue to be required.

Offsetting the foregoing increases to Revenue Deficiency is the approval of the Smart Meter Incremental Revenue Requirement (SMIRR) effective January 1, 2012. This increased distribution rates for both the residential and general service less than 50kw class. The total SMIRR approved in rates amounted to $1,364,127.

Rate Base

In this application Thunder Bay Hydro is applying for a rate base of $94,393,281 compared to a rate base of $75,533,273 which was approved during Thunder Bay Hydro's 2009 cost of service application which amounts to an increase of $18,860,008. The cost drivers of this increase are the following:

- The average NBV of the property, plant and equipment has increased $17,853,747. Three major transactions impacting the NBV are the smart meters rolling into the rate base (2012 closing NBV increase net of the removal of the stranded assets in 2009 is $4,553,065) and the new maintenance facility ($3,300,000) in the 2013 Test Year offset by the reduction resulting from the change to MCGAAP ($ 2,373,904). The three transactions impact the rate base by approximately $4,400,000. The balance of the

increase in the average NBV of the property, plant and equipment is the result of the annual investment exceeding the annual amortization on the assets as per Thunder Bay Hydro's asset management plan.

- Working capital allowance has increased by $1,006,261 from the 2009 Board Approved amount due to increases in the cost of power and increases in the applicant's operating expenses (including $141,072 relating to the change to MCGAAP) offset by a reduction in the working capital allowance rate from 15% to 13%.

Exhibit	Tab	Schedule	Appendix	Contents
7 – Cost Allocation				
	1	1		Cost Allocation Overview
		2		Summary of Results and Proposed Changes
			7-A	2013 Updated Cost Allocation Study

COST ALLOCATION OVERVIEW

Introduction

On September 29, 2006, the Board issued its directions on Cost Allocation Methodology for Electricity Distributors (the "Directions"). On November 15, 2006, the Board issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model (the "Model") and User Instructions (the "Instructions") for the Model. Thunder Bay Hydro prepared a cost allocation information filing consistent with Thunder Bay Hydro's understanding of the Directions, the Guidelines, the Model and the Instructions.

One of the main objectives of the filing was to provide information on any apparent cross-subsidization among a distributor's rate classifications. It was felt that this would give an indication of cross-subsidization from one class to another and this information would be useful as a tool in future rate applications.

In Thunder Bay Hydro's 2009 Cost of Service Application (EB-2008-0245), the results of the original cost allocation information filing were updated to correct inputs related to the number of connections and the distribution revenue associated with the Street Lighting and Unmetered Scattered Load classes. During the interrogatory phase, VECC suggested the cost allocation model should be further updated to exclude "costs" and class "revenues" associated with transformer ownership allowance and this was accepted by the Board. The results of this updated study were used as a basis for Thunder Bay Hydro to reallocate distribution revenues across customer classes to address the issue of cross-subsidization. The reallocations were based on the objective of moving the revenue to cost ratio over a four year period for the General Service 1000 to 4999 kW class to be within the Board's acceptable range as outlined in the "Report on Application of Cost Allocation for Electricity Distributors" (the Cost Allocation Report") issued by the OEB on November 28, 2007. In addition, the movement in the revenue to cost ratio for the General Service 50 - 999 kW class was to occur over two years to be within the Board's range and over two years for the Street Lighting class.

On September 2, 2010, the Board began a proceeding, EB-2010-0219, with the mandate to review and revise the existing Cost Allocation policy as needed. On March 31, 2011, the Report of the Board was released in relation to EB-2010-0219. In the letter accompanying report, the

Board indicated that a Working Group would be formed to revise the original Cost Allocation Model to address the revision highlighted in the March 31st Board Report. On August 5, 2011, the Board released the new Cost Allocation model and instructed 2012 Cost of Service filers to use the revised model in their applications. On June 28, 2012, the Board released a revised Cost Allocation model to be used by 2013 Cost of Service filers in their applications.

In the March 31st Board Report, the Board stated that "default weighting factors should now be utilized only in exceptional circumstances". Distributors are therefore now expected to develop their own weighting factors.

For the purposes of this Application, Thunder Bay Hydro has used the 2013 version of the cost allocation model and submitted the revised cost allocation study to reflect 2013 Test Year costs, customer numbers and demand values. The 2013 demand values are based on the weather normalized load forecast used to design rates. Thunder Bay Hydro has developed weighting factors as outlined below in Tables 7-1.1-7.1.4, based on discussions with staff experienced in the subject area.

Services (Account 1855)

Table 7-1.1: Service Weighting Factors	
Rate Class	Factor
Residential	1.0
General Service < 50 kW	4.4
General Service 50 to 999 kW	8.7
General Service 1,000 to 4,999 kW	8.7
Street Lighting	0.0
Sentinel Lighting	0.0
Unmetered Scattered Load	0.0

Billing and Collection (Accounts 5315 – 5340, except 5335)

Table 7-1.2: Billing Weighting Factors	
Rate Class	Factor
Residential	1.0
General Service < 50 kW	0.8
General Service 50 to 999 kW	4.9
General Service 1,000 to 4,999 kW	27.4
Street Lighting	27.4
Sentinel Lighting	0.3
Unmetered Scattered Load	0.3

Meter Capital (Sheet I7.1)

Table 7-1.3: Meter Capital Installation Costs	
Meter Type	Installation Cost per Meter
Smart Meter - Residential	$86.15
Smart Meter - General Service < 50 kW	$438.39
Demand without IT (usually three-phase)	$500
Demand with IT	$2,100
Demand with IT and Interval Capability - Secondary	$2,300
Demand with IT and Interval Capability - Primary	$10,000

Meter Reading (Sheet I7.2)

Table 7-1.4: Meter Reading Weighting Factor	
Meter Type	Factor
Residential	1.00
General Service < 50 kW	1.00
General Service 50 to 999 kW	13.26
General Service 1,000 to 4,999	0.67

SUMMARY OF RESULTS AND PROPOSED CHANGES

The data used in the updated cost allocation study is consistent with Thunder Bay Hydro's cost data that supports the proposed 2013 revenue requirement outlined in this Application. Consistent with the Guidelines, Thunder Bay Hydro's assets were broken out into primary and secondary distribution functions using current information on the distribution system. 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 Thunder Bay Hydro, its engineering records, and its customer and financial information systems. The cost allocation study has been included in Appendix 7-A.

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2013 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2013 customer forecast outlined in Exhibit 3. For the Street Lighting class, the number of connections reflects the actual number of connections of the street light system to Thunder Bay Hydro's distribution system. The load profiles for all rate class are the same as those used in the original information filing but have been scaled to match the 2013 load forecast. Tables 7-1.5 – 7-1.6 outlines the scaling factors used by rate class.

Table 7-1.5: Load Profile Scaling Percentages			
Rate Class	**2004 Weather Normal Values used in Original Filing (kWh)**	**2013 Weather Normal Values (KWh)**	**Scaling Factor**
Residential	372,479,625	335,941,782	90.2%
General Service < 50 kW	153,816,648	129,942,565	84.5%
General Service 50 to 999 kW	317,593,204	285,190,036	89.8%
General Service 1000 to 4999 kW	215,763,048	181,491,144	84.1%
Street Lighting	11,236,344	11,059,201	98.4%
Sentinel Lighting	139,956	121,120	86.5%
Unmetered Scattered Load	3,121,626	2,002,380	64.1%
Total	**1,074,150,451**	**945,748,229**	**88.0%**

The allocated cost by rate class from the original cost allocation study and the 2013 updated study are provided in the following Table 7-1.6.

Table 7-1.6: Allocated Cost - (Consistent with Appendix 2-P: Allocated Costs)				
Rate Class	**2009 Board Approved Cost Allocation Study**	%	**Cost Allocated in the 2013 Study**	%
Residential	$8,923,556	51.0%	$12,487,365	57.7%
General Service < 50 kW	$2,618,490	15.0%	$3,376,980	15.6%
General Service 50 to 999 kW	$2,920,602	16.7%	$3,963,735	18.3%
General Service 1000 to 4999 kW	$1,959,072	11.2%	$1,396,953	6.5%
Street Lighting	$1,022,368	5.8%	$357,756	1.7%
Sentinel Lighting	$11,327	0.1%	$15,231	0.1%
Unmetered Scattered Load	$49,465	0.3%	$54,770	0.3%
Total	$17,504,880	100.0%	$21,652,790	100.0%

The results of a cost allocation study are typically presented in the form of revenue-to-cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In the March 31, 2011 Report of the Board on Cost Allocation released in relation to EB-2010-0219, the Board established what it considered to be the appropriate ranges of revenue-to-cost ratios. Those are summarized in Table 7-1.7 below. In addition, Table 7-1.7 provides the revenue-to-cost ratios from: Thunder Bay Hydro's approved 2012 approved rate application (EB-2011-0197); the updated 2013 cost allocation study and the proposed 2013 to 2015 ratios.

Table 7-1.7 Revenue to Cost Ratios - (Consistent with Appendix 2-P: Revenue to Cost Ratios)

Class	2012 Board Approved	2013 Updated Cost Allocation Study	2013 Proposed Ratios	2014 Proposed Ratios	2015 Proposed Ratios	Board Targets Min to Max	
Residential	110.88%	100.31%	100.31%	100.31%	100.31%	85.0%	115.0%
General Service < 50 kW	114.32%	102.89%	102.89%	102.89%	102.89%	80.0%	120.0%
General Service 50 to 999 kW	80.00%	73.82%	87.40%	87.40%	87.40%	80.0%	120.0%
General Service 1000 to 4999 kW	73.14%	127.43%	120.00%	120.00%	120.00%	80.0%	120.0%
Street Lighting	70.00%	235.03%	120.00%	120.00%	120.00%	70.0%	120.0%
Sentinel Lighting	107.94%	106.57%	106.57%	106.57%	106.57%	80.0%	120.0%
Unmetered Scattered Load	113.68%	161.92%	120.00%	120.00%	120.00%	80.0%	120.0%

Thunder Bay Hydro is proposing in this Application to re-align its revenue-to-cost ratios by adjusting the allocations of revenue among rate classes in order to be within the Board's target range In addition, an adjustment is made to increase the ratio for the General Service 50 to 999 kW class above the Board's minimum value of the target range in order to maintain revenue neutrality.

The following table 7-1.8 provides information on calculated class revenue. The resulting 2013 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this Application.

Table 7-1.8 Calculated Class Revenue - (Consistent with Appendix 2-P: Calculated Class Revenue)

Class	2013 Base Revenue at Existing Rates	2013 Proposed Base Revenue Allocated at Existing Rates Proportion	2013 Proposed Base Revenue	Miscellaneous Revenue
Residential	$10,514,949	$11,408,885	$11,408,885	$1,117,353
General Service < 50 kW	$2,971,708	$3,224,349	$3,224,349	$250,293
General Service 50 to 999 kW	$2,455,695	$2,664,467	$3,202,670	$261,635
General Service 1000 to 4999 kW	$1,560,123	$1,692,758	$1,589,025	$87,318
Street Lighting	$748,504	$812,139	$400,628	$28,679
Sentinel Lighting	$13,317	$14,450	$14,450	$1,782
Unmetered Scattered Load	$77,425	$84,007	$61,047	$4,677
Total	$18,341,720	$19,901,055	$19,901,055	$1,751,736

APPENDICES

Appendix 7-A

2013 Updated Cost Allocation Study

As per Filing Requirements for Electricity Transmission and Distributors Application (EB-2006-0170) the following Cost Allocation Study sheets have been filed.

Input Sheets I-6.1, I-6.2 and I-8

Output Sheets O-1 and O-2

Appendix 7-A I-6.1

Sheet I6.1 Revenue Worksheet - Initial Application

Total kWhs from Load Forecast	945,748,229
Total kWs from Load Forecast	1,368,948
Deficiency from RRWF	- 1,559,334
Miscellaneous Revenue	1,751,736

	ID	Total	1 Residential	2 GS <50	3 General Service 50 to 999	5 General Service 1000 to 4999	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Billing Data									
Forecast kWh	CEN	945,748,229	335,941,782	129,942,565	285,190,036	181,491,144	11,059,201	121,120	2,002,380
Forecast kW	CDEM	1,368,948			774,872	562,588	31,152	336	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		667,000			117,670	549,330			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	945,748,229	335,941,782	129,942,565	285,190,036	181,491,144	11,059,201	121,120	2,002,380
kWh - 30 year weather normalized amount	Click here to Enter Data	945,748,229	335,941,782	129,942,565	285,190,036	181,491,144	11,059,201	121,120	2,002,380
Existing Monthly Charge			$11.72	$24.68	$241.78	$2,794.55	$2.16	$6.40	$8.91
Existing Distribution kWh Rate			$0.0124	$0.0130					$0.0130
Existing Distribution kW Rate					$1.3603	$2.2314	$13.0610	$5.1350	
Existing TFOA Rate					$0.60	$0.60			
Additional Charges									
Distribution Revenue from Rates		$18,741,920	$10,514,949	$2,971,708	$2,526,297	$1,889,721	$748,504	$13,317	$77,425
Transformer Ownership Allowance		$400,200	$0	$0	$70,602	$329,598	$0	$0	$0
Net Class Revenue	CREV	$18,341,720	$10,514,949	$2,971,708	$2,455,695	$1,560,123	$748,504	$13,317	$77,425
Data Mismatch Analysis									
Revenue with 30 year weather normalized kWh		18,341,720	10,514,949	2,971,708	2,455,695	1,560,123	748,504	13,317	77,425

Weather Normalized Data from Hydro One	Total	Residential	GS <50	General Service 50 to 999	General Service 1000 to 4999	Street Light	Sentinel	Unmetered Scattered Load
kWh - 30 year weather normalized amount	945,748,229	335,941,782	129,942,565	285,190,036	181,491,144	11,059,201	121,120	2,002,380
Loss Factor		**1.0000**	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000

Appendix 7-A I-6.2

Sheet I6.2 Customer Data Worksheet - Initial Application

			1	2	3	5	7	8	9
	ID	Total	Residential	GS <50	General Service 50 to 999	General Service 1000 to 4999	Street Light	Sentinel	Unmetered Scattered Load
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$75,450	$40,871	$6,679	$27,900	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$297,000	$208,765	$51,224	$31,089	$5,501	$21	$400	$0
Number of Bills	CNB	334,598	274,493	53,205	6,235	232	36	161	236
Number of Devices							13,180	151	481
Number of Connections (Unmetered)	CCON	2,981					2,349	151	481
Total Number of Customers	CCA	50,015	45,158	4,330	507	19			
Bulk Customer Base	CCB	-							
Primary Customer Base	CCP	50,015	45,158	4,330	507	19			
Line Transformer Customer Base	CCLT	49,955	45,158	4,330	463	3			
Secondary Customer Base	CCS	49,970	45,158	4,330	478	3			
Weighted - Services	CWCS	68,233	45,158	18,877	4,172	25	-	-	-
Weighted Meter -Capital	CWMC	6,864,425	3,890,396	1,898,221	1,032,300	43,508	-	-	-
Weighted Meter Reading	CWMR	56,230	45,158	4,330	6,728	13	-	-	-
Weighted Bills	CWNB	353,130	274,493	40,606	30,570	6,360	987	46	68

Bad Debt Data

Historic Year:	2010	110,203	59,697	9,755	40,751				
Historic Year:	2011	31,790	17,221	2,814	11,755				
Historic Year:	2012	84,356	45,696	7,467	31,193				
Three-year average		**75,450**	**40,871**	**6,679**	**27,900**	**-**	**-**	**-**	**-**

2013 Cost Allocation Model

Appendix 7-A I8

Sheet I8 Demand Data Worksheet - Initial Application

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 General Service 50 to 999	5 General Service 1000 to 4999	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	162,446	67,913	17,893	49,322	24,304	2,733	30	250
Bulk Delivery CP	BCP1	162,446	67,913	17,893	49,322	24,304	2,733	30	250
Total Sytem CP	DCP1	162,446	67,913	17,893	49,322	24,304	2,733	30	250
4 CP									
Transformation CP	TCP4	629,543	254,768	80,656	182,580	102,525	7,972	87	954
Bulk Delivery CP	BCP4	629,543	254,768	80,656	182,580	102,525	7,972	87	954
Total Sytem CP	DCP4	629,543	254,768	80,656	182,580	102,525	7,972	87	954
12 CP									
Transformation CP	TCP12	1,678,813	598,507	231,622	482,916	352,924	10,123	111	2,612
Bulk Delivery CP	BCP12	1,678,813	598,507	231,622	482,916	352,924	10,123	111	2,612
Total Sytem CP	DCP12	1,678,813	598,507	231,622	482,916	352,924	10,123	111	2,612
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	195,358	73,471	28,338	51,736	38,773	2,733	30	276
Primary NCP	PNCP1	195,358	73,471	28,338	51,736	38,773	2,733	30	276
Line Transformer NCP	LTNCP1	149,642	73,471	28,338	43,880	914	2,733	30	276
Secondary NCP	SNCP1	154,542	73,471	28,338	48,780	914	2,733	30	276
4 NCP									
Classification NCP from Load Data Provider	DNCP4	747,241	284,404	109,576	192,204	149,241	10,632	116	1,068
Primary NCP	PNCP4	747,241	284,404	109,576	192,204	149,241	10,632	116	1,068
Line Transformer NCP	LTNCP4	572,329	284,404	109,576	163,017	3,517	10,632	116	1,068
Secondary NCP	SNCP4	590,532	284,404	109,576	181,220	3,517	10,632	116	1,068
12 NCP									
Classification NCP from Load Data Provider	DNCP12	1,956,059	694,195	296,130	515,489	415,701	31,145	341	3,059
Primary NCP	PNCP12	1,956,059	694,195	296,130	515,489	415,701	31,145	341	3,059
Line Transformer NCP	LTNCP12	1,471,873	694,195	296,130	437,208	9,796	31,145	341	3,059
Secondary NCP	SNCP12	1,520,693	694,195	296,130	486,028	9,796	31,145	341	3,059

Appendix 7-A O-1

Sheet O1 Revenue to Cost Summary Worksheet - Initial Application

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 General Service 50 to 999	5 General Service 1000 to 4999	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$18,341,720	$10,514,949	$2,971,708	$2,455,695	$1,560,123	$748,504	$13,317	$77,425
mi	Miscellaneous Revenue (mi)	$1,751,736	$1,117,353	$250,293	$261,635	$87,318	$28,679	$1,782	$4,677
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$20,093,456	$11,632,301	$3,222,001	$2,717,329	$1,647,441	$777,183	$15,099	$82,102
	Factor required to recover deficiency (1 + D)	1.0850							
	Distribution Revenue at Status Quo Rates	$19,901,055	$11,408,885	$3,224,349	$2,664,467	$1,692,758	$812,139	$14,450	$84,007
	Miscellaneous Revenue (mi)	$1,751,736	$1,117,353	$250,293	$261,635	$87,318	$28,679	$1,782	$4,677
	Total Revenue at Status Quo Rates	$21,652,790	$12,526,237	$3,474,643	$2,926,102	$1,780,076	$840,818	$16,231	$88,684
	Expenses								
di	Distribution Costs (di)	$7,290,727	$3,938,127	$1,163,601	$1,452,643	$565,343	$143,257	$5,990	$21,766
cu	Customer Related Costs (cu)	$2,382,569	$1,781,006	$296,521	$266,493	$32,371	$5,444	$267	$465
ad	General and Administration (ad)	$4,745,550	$2,803,706	$716,969	$844,076	$293,493	$73,256	$3,086	$10,964
dep	Depreciation and Amortization (dep)	$3,510,812	$1,909,149	$604,007	$683,527	$240,540	$61,238	$2,599	$9,752
INPUT	PILs (INPUT)	$0	$0	$0	$0	$0	$0	$0	$0
INT	Interest	$1,080,120	$596,287	$172,872	$208,008	$76,939	$21,631	$954	$3,430
	Total Expenses	$19,009,778	$11,028,274	$2,953,970	$3,454,747	$1,208,687	$304,827	$12,896	$46,377
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$2,643,012	$1,459,091	$423,010	$508,987	$188,266	$52,930	$2,335	$8,393
	Revenue Requirement (includes NI)	$21,652,790	$12,487,365	$3,376,980	$3,963,735	$1,396,953	$357,756	$15,231	$54,770
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$175,802,072	$98,939,584	$29,124,164	$32,642,716	$10,969,924	$3,430,293	$151,159	$544,232
gp	General Plant - Gross	$16,456,067	$9,207,668	$2,655,675	$3,106,509	$1,085,992	$332,492	$14,828	$52,902
accum dep	Accumulated Depreciation	($95,403,965)	($53,832,557)	($16,122,330)	($17,530,785)	($5,750,875)	($1,803,579)	($78,476)	($285,364)
co	Capital Contribution	($16,948,001)	($10,172,788)	($2,863,447)	($2,845,087)	($633,667)	($358,282)	($16,859)	($57,870)
	Total Net Plant	$79,906,174	$44,141,907	$12,794,062	$15,373,353	$5,671,374	$1,600,924	$70,653	$253,900
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$97,020,439	$34,462,892	$13,330,276	$29,256,478	$18,618,433	$1,134,518	$12,425	$205,416
	OM&A Expenses	$14,418,846	$8,522,839	$2,177,092	$2,563,213	$891,208	$221,957	$9,343	$33,195
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$111,439,285*	*$42,985,731*	*$15,507,368*	*$31,819,691*	*$19,509,641*	*$1,356,476*	*$21,768*	*$238,611*
	Working Capital	$14,487,107	$5,588,145	$2,015,958	$4,136,560	$2,536,253	$176,342	$2,830	$31,019
	Total Rate Base	$94,393,281	$49,730,052	$14,810,020	$19,509,913	$8,207,627	$1,777,266	$73,483	$284,920
		Rate Base Input equals Output							
	Equity Component of Rate Base	$37,757,312	$19,892,021	$5,924,008	$7,803,965	$3,283,051	$710,906	$29,393	$113,968
	Net Income on Allocated Assets	$2,643,012	$1,497,963	$520,672	($528,646)	$571,389	$535,991	$3,335	$42,307
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$2,643,012	$1,497,963	$520,672	($528,646)	$571,389	$535,991	$3,335	$42,307
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	100.31%	102.89%	73.82%	127.43%	235.03%	106.57%	161.92%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($1,559,334)	($855,064)	($154,979)	($1,246,406)	$250,488	$419,427	($132)	$27,332
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	$38,872	$97,662	($1,037,633)	$383,123	$483,061	$1,000	$33,914
	RETURN ON EQUITY COMPONENT OF RATE BASE	7.00%	7.53%	8.79%	-6.77%	17.40%	75.40%	11.35%	37.12%

Appendix 7-A O-2

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Initial Application

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	5	7	8	9
	Residential	GS <50	General Service 50 to 999	General Service 1000 to 4999	Street Light	Sentinel	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$3.33	$7.96	$43.05	$74.40	$0.06	-$0.16	-$0.02
Customer Unit Cost per month - Directly Related	$4.93	$10.93	$61.91	$145.75	$0.16	-$0.09	$0.02
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.65	$27.58	$119.06	$538.88	$6.50	$8.07	$5.88
Existing Approved Fixed Charge	$11.72	$24.68	$241.78	$2,794.55	$2.16	$6.40	$8.91

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	5	7	8	9
	Total	Residential	GS <50	General Service 50 to 999	General Service 1000 to 4999	Street Light	Sentinel	Unmetered Scattered Load
General Plant - Gross Assets	$16,456,067	$9,207,668	$2,655,675	$3,106,509	$1,085,992	$332,492	$14,828	$52,902
General Plant - Accumulated Depreciation	($12,547,885)	($7,020,921)	($2,024,974)	($2,368,739)	($828,078)	($253,528)	($11,307)	($40,338)
General Plant - Net Fixed Assets	$3,908,182	$2,186,746	$630,701	$737,771	$257,914	$78,964	$3,522	$12,564
General Plant - Depreciation	$525,101	$293,810	$84,741	$99,126	$34,653	$10,610	$473	$1,688
Total Net Fixed Assets Excluding General Plant	$75,997,991	$41,955,161	$12,163,361	$14,635,583	$5,413,459	$1,521,960	$67,131	$241,336
Total Administration and General Expense	$4,745,550	$2,803,706	$716,969	$844,076	$293,493	$73,256	$3,086	$10,964
Total O&M	$9,673,296	$5,719,133	$1,460,122	$1,719,136	$597,714	$148,702	$6,257	$22,231

Exhibit	Tab	Schedule	Appendix	Contents
8 – Rate Design				
	1	1		Rate Design Overview
		2		Retail Transmission Service Rates
		3		Loss Factor
		4		Rate Mitigation
		5		Existing Rate Classes
		6		Existing Rate Schedule
		7		Proposed Rate Classes
		8		Proposed Rate Schedule
		9		Reconciliation of Rate Class Revenue
		10		Rate and Bill Impacts
			8-A	Existing Rate Schedule
			8-B	Proposed Rate Schedule
			8-C	Bill Impacts

RATE DESIGN OVERVIEW

DISTRIBUTION RATE DESIGN

This Exhibit documents the calculation of Thunder Bay Hydro's proposed distribution rates by rate class for the 2013 Test Year, based on the rate design as proposed in this Exhibit.

Thunder Bay Hydro has determined its total 2013 service revenue requirement to be $21,652,791. The total revenue offsets in the amount of $1,751,736 reduce Thunder Bay Hydro's total service revenue requirement to a base revenue requirement of $19,901,055 which is used to determine the proposed distribution rates. The revenue requirement is summarized in the Table 8-1.1 below:

Table 8-1.1 Calculation of Base Revenue Requirement

Description	Amount
OM&A Expenses	$ 14,658,215
Amortization Expenses	$ 3,247,244
Regulated Return On Capital	$ 3,723,132
Charitable Donation (LEAP)	$ 24,200
PILs	$ -
Service Revenue Requirement	$ 21,652,791
Less: Revenue Offsets	$ 1,751,736
Base Revenue Requirement	**$ 19,901,055**

The outstanding base revenue requirement is allocated to the various rate classes using the proposed revenue to cost ratios outlined in Exhibit 7 – Cost Allocation. The following Table 8-1.2 shows how the base revenue requirement has been allocated to the rate classes.

TABLE 8-1.2 Rate Class Base Revenue Requirement

Rate Classification	2013 Base Revenue Requirement
Residential	$ 11,408,885
General Service < 50 kW	$ 3,224,349
General Service 50 to 999 kW	$ 3,202,670
General Service 1000 to 4999 kW	$ 1,589,025
Street Lighting	$ 400,628
Sentinel Lighting	$ 14,450
Unmetered Scattered Load	$ 61,047
Total	**$ 19,901,055**

Determination of Monthly Fixed Charges

Based on applying the existing approved monthly service charges to the forecasted number of customers for 2013 and applying the existing approved distribution volumetric charge excluding the adjustment for transformation allowance, to 2013 forecasted volumes the following Table 8-1.3 outlines Thunder Bay Hydro's current split between fixed and variable distribution revenue.

Table 8-1.3 Current Fixed Variable Split

Rate Classification	2013 Fixed Base Revenue with 2012 Approved Rates	2013 Variable Base Revenue with 2012 Approved Rates	2013 Total Base Revenue with 2012 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	$ 5,337,723	$ 4,165,678	$ 9,503,401	56.2%	43.8%
General Service < 50 kW	$ 926,963	$ 1,689,253	$ 2,616,216	35.4%	64.6%
General Service 50 to 999 kW	$ 1,472,239	$ 983,456	$ 2,455,695	60.0%	40.0%
General Service 1000 to 4999 kW	$ 634,363	$ 925,760	$ 1,560,123	40.7%	59.3%
Street Lighting	$ 341,633	$ 406,871	$ 748,504	45.6%	54.4%
Sentinel Lighting	$ 11,590	$ 1,728	$ 13,317	87.0%	13.0%
Unmetered Scattered Load	$ 51,394	$ 26,031	$ 77,425	66.4%	33.6%
Total	**$ 8,775,904**	**$ 8,198,777**	**$ 16,974,681**	**51.7%**	**48.3%**

Consistent with recent Board Decisions on 2011 cost of service rate applications for Hydro One Brampton, Kenora Hydro and Horizon Utilities as well as the Board's Decision on Atikokan Hydro's 2013 cost of service application, Thunder Bay Hydro proposes to maintain the current fixed/variable proportions for all rate classes except for the Residential and General Service < 50 kW classes. For these two classes Thunder Bay Hydro is proposing to use the Customer Unit Cost per month - Minimum System with PLCC Adjustment or the Ceiling Value as outlined in Table 8-1.4

Table 8-1.4 Monthly Service Charge Information from Cost Allocaiton Model

Rate Classification	2012 Approved Monthly Service Charge	Customer Unit Cost per month - Avoided Cost	Customer Unit Cost per month - Minimum System with PLCC Adjustment
Residential	$9.85	$3.33	$13.65
General Service < 50 kW	$17.84	$7.96	$27.58
General Service 50 to 999 kW	$241.78	$43.03	$119.06
General Service 1000 to 4999 kW	$2,794.55	$74.22	$538.88
Street Lighting	$2.16	$0.06	$6.50
Sentinel Lighting	$6.40	($0.16)	$8.07
Unmetered Scattered Load	$8.91	($0.02)	$5.88

The current fixed/variable split for the Residential and General Service < 50 kW classes is lower for Thunder Bay Hydro than other distributors in the Northwestern Region. In addition, when the current approved 2012 smart meter incremental rate rider (SMIRR), which is assumed in the calculation of revenue at existing rate, is assumed in the determination of the fixed/variable split the resulting charge is close to the ceiling for the Residential class and higher than the ceiling for the General Service < 50 kW class. As a result, Thunder Bay Hydro submits it is appropriate to propose the monthly service charge for the Residential and General Service < 50 kW should be set at the ceiling. This in turn means the fixed component would be 56.2% for the Residential class and 35.4% for the General Service < 50 kW class. The following Table 8-1.5 outlines the calculation of the proposed monthly service charge by rate class.

Table 8-1.5 Proposed Monthly Service Charge

Rate Classification	Total Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue	Annualized Customers / Connections	Proposed Monthly Service Charge
Residential	$ 11,408,885	64.8%	$ 7,396,247	541,901	$13.65
General Service < 50 kW	$ 3,224,349	44.4%	$ 1,433,204	51,960	$27.58
General Service 50 to 999 kW	$ 3,202,670	60.0%	$ 1,920,066	6,089	$315.32
General Service 1000 to 4999 kW	$ 1,589,025	40.7%	$ 646,115	227	$2,846.32
Street Lighting	$ 400,628	45.6%	$ 182,855	158,164	$1.16
Sentinel Lighting	$ 14,450	87.0%	$ 12,575	1,811	$6.94
Unmetered Scattered Load	$ 61,047	66.4%	$ 40,522	5,768	$7.03
Total	**$ 19,901,055**		**$ 11,631,584**		

Proposed Volumetric Charges

The volumetric distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate 2013 Test Year usage, kWh or kW, as the class charge determinant.

The following Table 8-1.6 provides Thunder Bay Hydro's calculations of its proposed volumetric distribution charges for the 2013 Test Year assuming the fixed/variable split used in designing the monthly service charge.

Table 8-1.6 Proposed Distribution Volumetric Charge

Rate Classification	Total Base Revenue Requirement	Fixed Revenue	Variable Revenue	Annualized kWh or kW as required	Unit of Measure	Proposed Volumetric Distribution Charge before Transformer Allowance
Residential	$ 11,408,885	$ 7,396,247	$ 4,012,638	335,941,782	kWh	$0.0119
General Service < 50 kW	$ 3,224,349	$ 1,433,204	$ 1,791,146	129,942,565	kWh	$0.0138
General Service 50 to 999 kW	$ 3,202,670	$ 1,920,066	$ 1,282,605	774,872	kW	$1.6552
General Service 1000 to 4999 kW	$ 1,589,025	$ 646,115	$ 942,911	562,588	kW	$1.6760
Street Lighting	$ 400,628	$ 182,855	$ 217,773	31,152	kW	$6.9908
Sentinel Lighting	$ 14,450	$ 12,575	$ 1,875	336	kW	$5.5716
Unmetered Scattered Load	$ 61,047	$ 40,522	$ 20,525	2,002,380	kWh	$0.0103
Total	**$ 19,901,055**	**$ 11,631,584**	**$ 8,269,471**			

Proposed Adjustment for Transformer Allowance

Currently, Thunder Bay Hydro provides a Transformer Allowance to those customers that own their transformation facilities. Thunder Bay Hydro proposes to maintain the current approved transformer ownership allowance of $0.60 per kW. However, in order to ensure Thunder Bay Hydro collects the proposed distribution revenue assigned to the rate class, which provides a Transformer Allowance, the total amount or "cost" of the Transformer Allowance for the rate class needs to be collected in the distribution volumetric rates from all customers in the class. This will allow Thunder Bay Hydro to collect distribution revenue from the rate class at the "gross" level. Then provide a Transformer Allowance which will reduce the gross distribution revenue to a "net" level. The net level amount will be equivalent to the proposed distribution assigned to the rate class

As a result, the amount of Transformer Allowance expected to be provided to that General Service 50 to 999 kW and General Service 1,000 to 4,999 kW customers that own their transformers is included in the volumetric charge for the class. The proposed "net" volumetric charge of $1.6552 per kW for the General Service 50 to 999 kW class is increased by $0.0912 per kW to include $70,602 or the "cost" of the Transformer Allowance in the General Service 50 to 999 kW class volumetric charges. This means the "gross" proposed distribution volumetric charge for this class will be $1.7464. Similarly the volumetric charge for General Service 1,000 to 4,999 kW class will increase from $1.6760 per kW to $2.2619 per kW to recover $329,598 or the "cost" of Transformer Allowance for this class.

Proposed Distribution Rates

Table 8-1.7, sets out Thunder Bay Hydro's proposed 2011 electricity distribution rates based on the foregoing calculations.

Table 8-1.7 Proposed Distribution Rates

Rate Classification	Proposed Monthly Service Charge	Unit of Measure	Proposed Volumetric Distribution Charge incl Transformer Allowance Adjustment
Residential	$13.65	kWh	$0.0119
General Service < 50 kW	$27.58	kWh	$0.0138
General Service 50 to 999 kW	$315.32	kW	$1.7464
General Service 1000 to 4999 kW	$2,846.32	kW	$2.2619
Street Lighting	$1.16	kW	$6.9908
Sentinel Lighting	$6.94	kW	$5.5716
Unmetered Scattered Load	$7.03	kWh	$0.0103
Transformer Discount		kW	($0.60)

RETAIL TRANSMISSION SERVICE RATES

Electricity distributors are charged the Ontario Uniform Transmission Rates (UTRs) at the wholesale level and subsequently pass these charges on to their distribution customers through Retail Transmission Service Rates (RTSRs). For each distribution rate class there are two RTSRs, one for network and one for connection. The RTSR network charge recovers the UTR wholesale network service charge, and the RTSR connection charge recovers the UTR wholesale line and transformation connection charges. Deferral accounts capture timing and rate differences between the UTR's paid at the wholesale level and RTSR's billed to distribution customers.

The Board has provided a Microsoft Excel workbook "RTSR_Adjustment_Work_Form – version 3.0" and instructions on June 28, 2012 for distributors to complete as part of their 2013 electricity rate applications. Thunder Bay Hydro has completed this workbook to determine the RTSR's and has filed the model as part of this application. Table 8-1.8 is reproduced from the Board model and indicates the new RTSR's**.**

Table 8-1.8 - Final 2013 RTS Rates

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	$ 0.0064	$ 0.0048
General Service Less Than 50 kW	kWh	$ 0.0061	$ 0.0046
General Service 50 to 999 kW	kW	$ 2.4130	$ 1.7275
General Service 50 to 999 kW - Interval Metered	kW	$ 2.5597	$ 1.9093
General Service 1,000 to 4,999 kW	kW	$ 2.5597	$ 1.9093
Unmetered Scattered Load	kWh	$ 0.0061	$ 0.0046
Sentinel Lighting	kW	$ 1.8291	$ 1.3635
Street Lighting	kW	$ 1.8197	$ 1.3354

LOSS FACTOR

DETERMINATION OF LOSS ADJUSTMENT FACTORS

Total Loss Factor

Thunder Bay Hydro has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2007 to 2011. The calculations are summarized in Table 8-1.9 below.

Table 8-1.9 -Line Loss Calculation

		Historical Years					5-Year Average
		2007	2008	2009	2010	2011	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	1,074,730,324	1,046,425,967	1,013,620,981	981,474,626	996,978,410	1,022,646,062
A(2)	"Wholesale" kWh delivered to distributor (lower value)	1,069,209,445	1,041,068,320	1,007,898,659	975,397,924	991,412,278	1,016,997,325
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	0	0	0	0	0	0
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	1,069,209,445	1,041,068,320	1,007,898,659	975,397,924	991,412,278	1,016,997,325
D	"Retail" kWh delivered by distributor	1,031,531,518	1,005,783,317	976,849,071	944,456,544	958,150,425	983,354,175
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)	0	0	0	0	0	0
F	Net "Retail" kWh delivered by distributor = **D - E**	1,031,531,518	1,005,783,317	976,849,071	944,456,544	958,150,425	983,354,175
G	Loss Factor in Distributor's system = **C / F**	1.0365	1.0351	1.0318	1.0328	1.0347	1.0342
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0045	1.0045	1.0045	1.0045	1.0045	1.0045
	Total Losses						
I	Total Loss Factor = **G x H**	1.0412	1.0397	1.0364	1.0374	1.0394	1.0389

Thunder Bay Hydro has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2007 to 2011. As a result of this analysis, Thunder Bay Hydro is proposing to set the 2013 Total Loss Factor at 1.0389. This represents the 5 year average from 2007 to 2011.

Table 8-1.10, sets out the class-specific Loss Factors used by Thunder Bay Hydro in the calculation of commodity and other non-distribution charges for the 2013 Test Year.

Table 8.1.10 Total Loss Factor by Class

Loss Factors	
Supply Facilities Loss Factor (5 year average)	1.0045
Distribution Loss Factor - Secondary Metered Customers < 5,000 kW	1.0342
Distribution Loss Factor - Primary Metered Customers < 5,000 kW	1.0239
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0389
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0285

Thunder Bay Hydro confirms that it is not an embedded distributor and that no loss study has been recommended in a previous decision by the Board.

Materiality Analysis on Distribution Losses

Thunder Bay Hydro's Distribution Loss Adjustment factor is 3.42%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is less than 5%, Thunder Bay Hydro is not required to provide an explanation of, or justification for, its loss adjustment factor.

RATE MITIGATION

Thunder Bay Hydro submits that the bill impacts of its proposed 2013 electricity distribution rates for all rate classes except General Service 50 to 999 kW and Sentinel Lights are under 10% and therefore do not require rate mitigation.

The General Service 50 to 999 kW class has total bill impacts over 10% due to the adjustment resulting from the 2013 cost allocation study discussed in Exhibit 7 and the impact of the change of the Global Adjustment rate rider from a refund in May 1, 2012 rates to a charge proposed May 1, 2013. As outlined in Exhibit 7, Thunder Bay Hydro is proposing in this Application to re-align its revenue-to-cost ratios by adjusting the allocations of revenue among rate classes in order to be within the Board's target range However, an adjustment is made to increase the ratio for the General Service 50 to 999 kW class above the Board's minimum value of the target range in order to maintain revenue neutrality. As a result, Thunder Bay Hydro has proposed to move this customer class from below the Board's target range to 6.1% above the bottom range of acceptable Revenue to Cost ratio. This has resulted in this class experiencing a higher increase than the other customer classes.

The total bill impact for the Sentinel Lights class is over 10%. This increase is primarily due to the discontinuation of the refund received as a result of the 2012 IRM Deferral and Variance and tax change rate riders and the commencement of the proposed Deferral and Variance rate rider as a charge effective May 1, 2013. See Exhibit 9 for additional details of this calculation of the rate rider.

EXISTING RATE CLASSES

Residential

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50kW

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads.

General Service Greater Than 50 to 999 kW

This classification refers to a non-residential account whose monthly average peak demand is greater than, or is forecast to be greater than, 50 kW to 999 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, restaurants, office buildings, hotels, motels, schools, colleges, arenas and other comparable premises.

General Service Greater Than 1,000 to 4,999 kW

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 1,000 kW to 4,999 kW.

Unmetered Scattered Load

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, private sentinel lighting, etc. The customer will provide detailed

manufacturer information/documentation with regard to electrical demand/ consumption of the proposed unmetered load.

Sentinel Lighting

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

EXISTING RATE SCHEDULE

Thunder Bay Hydro has attached the Board's Decision and Order from its 2012 Rate Application (EB-2011-0197) in Appendix 8-A, which contains a complete schedule of existing rates.

PROPOSED RATE CLASSES

Thunder Bay Hydro is not requesting any changes to the existing rate classes.

PROPOSED RATE SCHEDULE

Please see Appendix 8-B, for Thunder Bay Hydro's proposed Rate Schedule for Rates effective May 1, 2013.

RECONCILIATION OF RATE CLASS REVENUE

Table 8-1.11 provides reconciliation between the 2013 distribution rate calculations based on the 2013 Proposed Rates and the total base revenue required. The reconciliation yields an acceptable difference.

Table 8-1.11 -Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential	Customers	45,158	45,158	45,158.40	335,941,782		$ 13.65	$ 0.0119		$ 11,394,652.85	$ 11,408,885		$ 11,408,885	$ 14,232
GS < 50 kW	Customers	4,330	4,330	4,329.98	129,942,565		$ 27.58	$ 0.0138		$ 3,226,258.48	$ 3,224,349		$ 3,224,349	-$ 1,909
GS > 50 to 999 kW	Customers	507	507	507.43	285,190,036	774,872	$ 315.32		$ 1.7464	$ 3,273,271.94	$ 3,202,670	$ 70,602	$ 3,273,272	$ 0
GS > 1,000 to 4,999 kW	Customers	19	19	18.92	181,491,144	562,588	$ 2,846.32		$ 2.2619	$ 1,918,631.91	$ 1,589,025	$ 329,598	$ 1,918,623	-$ 8
Streetlighting	Connections	13,180	13,180	13,180.30	11,059,201	31,152	$ 1.16		$ 6.9908	$ 400,627.31	$ 400,628		$ 400,628	$ 1
Sentinel Lighting	Connections	151	151	150.91	121,120	336	$ 6.94		$ 5.5716	$ 14,449.61	$ 14,450		$ 14,450	-$ 0
Unmetered Scattered Load	Connections	481	481	480.67	2,002,380		$ 7.03	$ 0.0103		$ 61,147.14	$ 61,047		$ 61,047	-$ 100
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total		63,827	63,827		945,748,229	1,368,948				$ 20,289,039.24	$ 19,901,055	$ 400,200	$ 20,301,255	$ 12,216

Note

RATE AND BILL IMPACTS

Appendix 8-C, to this Exhibit presents the results of the assessment of customer total bill impacts by level of consumption by customer per rate class and per the total customer class.

Impacts are shown using the applicable current approved rates and the proposed 2013 distribution rates, including rate riders for the disposition of Deferral and Variance Accounts, as discussed in Exhibit 9.

The total bill impacts are calculated at an average consumption level as calculated from 2011 actuals for each rate class, except for the Residential and General Service < 50 kW rate classes which are calculated at 800 kWh and 2,000 kWh per month, respectively. The rate impacts are assessed on the basis of moving to the proposed distribution rates.

APPENDICES

APPENDIX 8-A
EXISTING RATE SCHEDULE

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

RESIDENTIAL SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	9.85
Distribution Volumetric Rate	$/kWh	0.0124
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0034)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.00004
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0003)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. This class includes small commercial services such as small stores, small service stations, restaurants, churches, small offices and other establishments with similar loads. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	17.84
Distribution Volumetric Rate	$/kWh	0.0130
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0030)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kWh	0.00020
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0002)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

GENERAL SERVICE 50 to 999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,000 kW. This class includes medium and large-size commercial buildings, apartment buildings, condominiums, trailer courts, industrial plants, as well as large stores, shopping centers, hospitals, manufacturing or processing plants, garages, storage buildings, hotels, motels, schools, colleges, arenas and other comparable premises. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply:

General Service 50 to 1,000 kW non-interval metered
General Service 50 to 1,000 kW interval metered.

Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	241.78
Distribution Volumetric Rate	$/kW	1.3603
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.9127)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(0.1051)
Rate Rider for Lost Revenue Adjustment Mechanism (LRAM) Recovery – effective until April 30, 2013	$/kW	0.00011
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0410)
Retail Transmission Rate – Network Service Rate	$/kW	2.4300
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7458
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5777
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9295

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

GENERAL SERVICE 1,000 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 1,000 kW but less than 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	2,794.55
Distribution Volumetric Rate	$/kW	2.2314
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(0.7755)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(0.0924)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.0371)
Retail Transmission Rate – Network Service Rate	$/kW	2.5777
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9295

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, private sentinel lighting etc. The customer will provide detailed manufacturing information/documentation with regard to electrical demand/ consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	8.91
Distribution Volumetric Rate	$/kWh	0.0130
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kWh	(0.0044)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kWh	(0.0003)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kWh	(0.0005)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	6.40
Distribution Volumetric Rate	$/kW	5.1350
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(2.4061)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.4698)
Retail Transmission Rate – Network Service Rate	$/kW	1.8420
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3779

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photocells. The consumption for these customers will be based on the calculated load times the required lighting times established in the approved OEB street lighting load shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	2.16
Distribution Volumetric Rate	$/kW	13.0610
Rate Rider for Deferral/Variance Account Disposition (2012) – effective until April 30, 2013	$/kW	(1.5474)
Rate Rider for Global Adjustment Sub-Account Disposition (2012) – effective until April 30, 2013 Applicable only for Non-RPP Customers	$/kW	(0.1097)
Rate Rider for Tax Adjustments - effective until April 30, 2013	$/kW	(0.2863)
Retail Transmission Rate – Network Service Rate	$/kW	1.8325
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3496

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	5.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	25.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Disconnect/Reconnect charge - At Meter – during regular hours	$	65.00
Disconnect/Reconnect charge - At Meter – after regular hours	$	185.00
Disconnect/Reconnect charge - At Pole - during regular hours	$	185.00
Disconnect/Reconnect charge - At Pole - after regular hours	$	415.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2012

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2011-0197

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0448
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0343

APPENDIX 8-B
PROPOSED RATE SCHEDULE

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013
Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0167

RESIDENTIAL SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	13.65
Smart Meter Disposition - Effective Until April 30, 2014	$	-1.58
Stranded Asset Rate Rider - Effective Until April 30, 2014	$	2.27
GEA Funding Adder - Effective Until April 30, 2017	$	0.0022
Distribution Volumetric Rate	$/kWh	0.0119
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kWh	-0.0028
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kWh	0.002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0048

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	27.58
Smart Meter Disposition - Effective Until April 30, 2014	$	4.19
Stranded Asset Rate Rider - Effective Until April 30, 2014	$	6.52
GEA Funding Adder - Effective Until April 30, 2017	$	0.0022
Distribution Volumetric Rate	$/kWh	0.0138
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kWh	-0.0035
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kWh	0.002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013
Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0167

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	315.32
GEA Funding Adder - Effective Until April 30, 2017	$	0.0022
Distribution Volumetric Rate	$/kW	1.7464
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kW	-1.458
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kW	0.7802
Retail Transmission Rate – Network Service Rate	$/kW	2.413
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.5597
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7275
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9093

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	2,846.32
GEA Funding Adder - Effective Until April 30, 2017	$	0.0022
Distribution Volumetric Rate	$/kW	2.2619
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kW	-1.323
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kW	0.7057
Retail Transmission Rate – Network Service Rate	$/kW	2.5597
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9093

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013
Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0167

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7.03
Distribution Volumetric Rate	$/kWh	0.0103
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kWh	-0.0036
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kWh	0.002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0046

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	6.94
Distribution Volumetric Rate	$/kW	5.5716
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kW	1.6015
Retail Transmission Rate – Network Service Rate	$/kW	1.8291
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3635

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013
Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0167

STREET LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES - Delivery Component		
Service Charge	$	1.16
Distribution Volumetric Rate	$/kW	6.9908
Rate Rider for Deferral/Variance Account Disposition (2013)	$/kW	-1.3308
Rate Rider for Global Adjustment Sub-Account (2013) – Applicable only for Non-RPP Customers	$/kW	0.71
Retail Transmission Rate – Network Service Rate	$/kW	1.8197
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3354
MONTHLY RATES AND CHARGES – Regulatory Component		
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0011
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's micoFIT program and connected to the distribuor's distribution system. Further servicing details are available in the distributor's Condition of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule unless required by the Distributor's Licence or a Code or Order ofthe Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, beit under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be notedthat this schedule does not list any charges, assessments, or credits that are required by law to beinvoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Programs, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

1	Service Charge	$	5.40

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013
Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

		EB-2012-0167
ALLOWANCES		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Easement letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	25.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Disconnect/Reconnect at meter - during regular hours	$	65.00
Disconnect/Reconnect at meter - after regular hours	$	185.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Install/Remove load control device - during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00
Service call - customer-owned equipment	$	30.00
Service Call - Customer-owned Equipment - After Regular Hours	$	165.00
Specific Charge for Access to the Power Poles - per pole/year	$	22.35

Thunder Bay Hydro Electricity Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective Date May 1, 2013
Implementation Date May 1, 2013

EB-2012-0167

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factor will be implemented upon the first subsequent billing for each billing cycle.

Secondary Metered Customers - Cusomers < 5,000 (RS, GU, GC, GS, G3, G8, M3, ST)	1.0342
Primary Metered Customers - Customers < 5,000 (GP, G1, G2, G9, M1, M2)	1.0239

APPENDIX 8-C
BILL IMPACTS

Customer Class: **Residential**

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

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 9.8500	1	$ 9.85	$ 13.6500	1	$ 13.65	$ 3.80	38.58%
Smart Meter Incremental Rev Req	Monthly	$ 1.8667	1	$ 1.87	$ -	1	$ -	$ (1.87)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0124	800	$ 9.92	$ 0.0119	800	$ 9.52	$ (0.40)	(4.03%)
Smart Meter Disposition Rider	Monthly	$ (1.3167)	1	$ (1.32)	$ (1.3167)	1	$ (1.32)	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.00004	800	$ 0.03	$ -	800	$ -	$ (0.03)	(100.00%)
Stranded Asset Rate Rider	Monthly	$ -	1	$ -	$ 2.2700	1	$ 2.27	$ 2.27	
Sub-Total A				$ 20.35			$ 24.12	**$ 3.77**	**18.53%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0034)	800	$ (2.72)	$ (0.0028)	800	$ (2.24)	$ 0.48	(17.65%)
Tax Charge Rate Rider	per kWh	$ (0.0003)	800	$ (0.24)		800	$ -	$ 0.24	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge						800	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 17.39**			**$ 21.89**	**$ 4.49**	**25.84%**
RTSR - Network	per kWh	$ 0.0064	836	$ 5.35	$ 0.0064	827	$ 5.30	$ (0.05)	(1.01%)
RTSR - Line and Transformation Connection	per kWh	$ 0.0049	836	$ 4.10	$ 0.0048	827	$ 3.97	$ (0.12)	(3.03%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 26.84**			**$ 31.15**	**$ 4.31**	**16.08%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	836	$ 4.35	$ 0.0052	827	$ 4.30	$ (0.04)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	836	$ 0.92	$ 0.0011	827	$ 0.91	$ (0.01)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	836	$ 5.85	$ 0.0070	827	$ 5.79	$ (0.06)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	800	$ 59.20	$ 0.0740	800	$ 59.20	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	535	$ 33.70	$ 0.0630	530	$ 33.36	$ (0.34)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	150	$ 14.89	$ 0.0990	149	$ 14.74	$ (0.15)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	150	$ 17.75	$ 0.1180	149	$ 17.57	$ (0.18)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 97.40**			**$ 101.61**	**$ 4.20**	**4.31%**
HST		13%		$ 12.66	13%		$ 13.21	$ 0.55	4.31%
Total Bill (including HST)				$ 110.07			$ 114.81	$ 4.75	4.31%
Ontario Clean Energy Benefit [1]				$ (11.01)			$ (11.48)	$ (0.47)	4.27%
Total Bill on RPP (including OCEB)				**$ 99.06**			**$ 103.33**	**$ 4.28**	**4.32%**
Total Bill on TOU (before Taxes)				**$ 104.55**			**$ 108.08**	**$ 3.53**	**3.38%**
HST		13%		$ 13.59	13%		$ 14.05	$ 0.46	3.38%
Total Bill (including HST)				$ 118.14			$ 122.13	$ 3.99	3.38%
Ontario Clean Energy Benefit [1]				$ (11.81)			$ (12.21)	$ (0.40)	3.39%
Total Bill on TOU (including OCEB)				**$ 106.33**			**$ 109.92**	**$ 3.59**	**3.37%**

Loss Factor (%) 4.48% 3.42%

Customer Class: **General Service Less Than 50 kW**

Consumption **2000** **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 17.8400	1	$ 17.84	$ 27.5800	1	$ 27.58	$ 9.74	54.60%
Smart Meter Incremental Rev Req	Monthly	$ 6.8417	1	$ 6.84	$ -	1	$ -	$ (6.84)	(100.00%)
Distribution Volumetric Rate	per kWh	$ 0.0130	2000	$ 26.00	$ 0.0138	2000	$ 27.60	$ 1.60	6.15%
Smart Meter Disposition Rider	Monthly	$ 3.4917	1	$ 3.49	$ 3.4917	1	$ 3.49	$ -	0.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40	$ -	2000	$ -	$ (0.40)	(100.00%)
Stranded Asset Rate Rider	Monthly		1	$ -	$ 6.5200	1	$ 6.52	$ 6.52	
Sub-Total A				$ 54.57			$ 65.19	**$ 10.62**	**19.46%**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0030)	2000	$ (6.00)	$ (0.0035)	2000	$ (7.00)	$ (1.00)	16.67%
Tax Charge Rate Rider	per kWh	$ (0.0002)	2000	$ (0.40)	$ -	2000	$ -	$ 0.40	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 48.17**			**$ 58.19**	**$ 10.02**	**20.80%**
RTSR - Network	per kWh	$ 0.0061	2090	$ 12.75	$ 0.0061	2068	$ 12.62	$ (0.13)	(1.01%)
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2090	$ 9.61	$ 0.0046	2068	$ 9.51	$ (0.10)	(1.01%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 70.53**			**$ 80.33**	**$ 9.79**	**13.89%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2090	$ 10.87	$ 0.0052	2068	$ 10.76	$ (0.11)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	2090	$ 2.30	$ 0.0011	2068	$ 2.28	$ (0.02)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2090	$ 14.63	$ 0.0070	2068	$ 14.48	$ (0.15)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1000	$ 87.00	$ 0.0870	1000	$ 87.00	$ -	0.00%
TOU - Off Peak	per kWh	$ 0.0630	1337	$ 84.25	$ 0.0630	1324	$ 83.40	$ (0.85)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	376	$ 37.24	$ 0.0990	372	$ 36.86	$ (0.38)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	376	$ 44.38	$ 0.1180	372	$ 43.93	$ (0.45)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 259.57**			**$ 269.09**	**$ 9.51**	**3.66%**
HST		13%		$ 33.74	13%		$ 34.98	$ 1.24	3.66%
Total Bill (including HST)				$ 293.32			$ 304.07	$ 10.75	3.66%
Ontario Clean Energy Benefit [1]				$ (29.33)			$ (30.41)	$ (1.08)	3.68%
Total Bill on RPP (including OCEB)				**$ 263.99**			**$ 273.66**	**$ 9.67**	**3.66%**
Total Bill on TOU (before Taxes)				**$ 264.45**			**$ 272.28**	**$ 7.83**	**2.96%**
HST		13%		$ 34.38	13%		$ 35.40	$ 1.02	2.96%
Total Bill (including HST)				$ 298.82			$ 307.67	$ 8.85	2.96%
Ontario Clean Energy Benefit [1]				$ (29.88)			$ (30.77)	$ (0.89)	2.98%
Total Bill on TOU (including OCEB)				**$ 268.94**			**$ 276.90**	**$ 7.96**	**2.96%**

Loss Factor (%) 4.48% 3.42%

Customer Class: **General Service 50 to to 999 kW**

Consumption 100 **kW** ○ May 1 - October 31 ◉ 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	$ 241.7800	1	$ 241.78	$ 315.3200	1	$ 315.32	$ 73.54	30.42%
Distribution Volumetric Rate	per kW	$ 1.3603	100	$ 136.03	$ 1.7464	100	$ 174.64	$ 38.61	28.38%
LRAM & SSM Rate Rider	per kW	$ 0.00011			$ -			$ -	
Sub-Total A				$ 377.81			$ 489.96	**$ 112.15**	**29.68%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.9127)	100	$ (91.27)	$ (1.4580)	100	$ (145.80)	$ (54.53)	59.75%
Global Adjustment Rate Rider	per kW	$ (0.1051)	100	$ (10.51)	$ 0.7802	100	$ 78.02	$ 88.53	(842.34%)
Tax Charge Rate Rider	per kW	$ (0.0410)	100	$ (4.10)	$ -	100	$ -	$ 4.10	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge					$ -	100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 271.93**			**$ 422.18**	**$ 150.25**	**55.25%**
RTSR - Network	per kW	$ 2.4300	104	$ 253.89	$ 2.4130	103	$ 249.55	$ (4.33)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.7458	104	$ 182.40	$ 1.7275	103	$ 178.66	$ (3.74)	(2.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 708.22**			**$ 850.39**	**$ 142.18**	**20.08%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	104	$ 0.54	$ 0.0052	103	$ 0.54	$ (0.01)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	104	$ 0.11	$ 0.0011	103	$ 0.11	$ (0.00)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	104	$ 0.73	$ 0.0070	103	$ 0.72	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	100	$ 7.40	$ 0.0740	100	$ 7.40	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kW	$ 0.0630	67	$ 4.21	$ 0.0630	66	$ 4.17	$ (0.04)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	19	$ 1.86	$ 0.0990	19	$ 1.84	$ (0.02)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	19	$ 2.22	$ 0.1180	19	$ 2.20	$ (0.02)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 717.26**			**$ 859.42**	**$ 142.16**	**19.82%**
HST		13%		$ 93.24	13%		$ 111.72	$ 18.48	19.82%
Total Bill (including HST)				$ 810.50			$ 971.14	$ 160.64	19.82%
Ontario Clean Energy Benefit [1]				$ (81.05)			$ (97.11)	$ (16.06)	19.81%
Total Bill on RPP (including OCEB)				**$ 729.45**			**$ 874.03**	**$ 144.58**	**19.82%**
Total Bill on TOU (before Taxes)				**$ 718.15**			**$ 860.23**	**$ 142.08**	**19.78%**
HST		13%		$ 93.36	13%		$ 111.83	$ 18.47	19.78%
Total Bill (including HST)				$ 811.51			$ 972.06	$ 160.55	19.78%
Ontario Clean Energy Benefit [1]				$ (81.15)			$ (97.21)	$ (16.06)	19.79%
Total Bill on TOU (including OCEB)				**$ 730.36**			**$ 874.85**	**$ 144.49**	**19.78%**

Loss Factor (%) 4.48% 3.42%

Customer Class: **General Service 50 to to 999 kW Interval Metered**

Consumption 100 **kW** ○ May 1 - October 31 ◉ 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	$ 241.7800	1	$ 241.78	$ 315.3200	1	$ 315.32	$ 73.54	30.42%
Distribution Volumetric Rate	per kW	$ 1.3603	100	$ 136.03	$ 1.7464	100	$ 174.64	$ 38.61	28.38%
LRAM & SSM Rate Rider	per kW	$ 0.00011			$ -			$ -	
Sub-Total A				$ 377.81			$ 489.96	**$ 112.15**	**29.68%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.9127)	100	$ (91.27)	$ (1.4580)	100	$ (145.80)	$ (54.53)	59.75%
Global Adjustment Rate Rider	per kW	$ (0.1051)	100	$ (10.51)	$ 0.7802	100	$ 78.02	$ 88.53	(842.34%)
Tax Charge Rate Rider	per kW	$ (0.0410)	100	$ (4.10)	$ -	100	$ -	$ 4.10	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge					$ -	100	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 271.93**			**$ 422.18**	**$ 150.25**	**55.25%**
RTSR - Network	per kW	$ 2.5777	104	$ 269.32	$ 2.5597	103	$ 264.72	$ (4.59)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.9295	104	$ 201.59	$ 1.9093	103	$ 197.46	$ (4.13)	(2.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 742.84**			**$ 884.37**	**$ 141.52**	**19.05%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	104	$ 0.54	$ 0.0052	103	$ 0.54	$ (0.01)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	104	$ 0.11	$ 0.0011	103	$ 0.11	$ (0.00)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	104	$ 0.73	$ 0.0070	103	$ 0.72	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	100	$ 7.40	$ 0.0740	100	$ 7.40	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kW	$ 0.0630	67	$ 4.21	$ 0.0630	66	$ 4.17	$ (0.04)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	19	$ 1.86	$ 0.0990	19	$ 1.84	$ (0.02)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	19	$ 2.22	$ 0.1180	19	$ 2.20	$ (0.02)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 751.88**			**$ 893.39**	**$ 141.51**	**18.82%**
HST		13%		$ 97.74	13%		$ 116.14	$ 18.40	18.82%
Total Bill (including HST)				$ 849.63			$ 1,009.53	$ 159.91	18.82%
Ontario Clean Energy Benefit [1]				$ (84.96)			$ (100.95)	$ (15.99)	18.82%
Total Bill on RPP (including OCEB)				**$ 764.67**			**$ 908.58**	**$ 143.92**	**18.82%**
Total Bill on TOU (before Taxes)				**$ 752.78**			**$ 894.20**	**$ 141.43**	**18.79%**
HST		13%		$ 97.86	13%		$ 116.25	$ 18.39	18.79%
Total Bill (including HST)				$ 850.64			$ 1,010.45	$ 159.81	18.79%
Ontario Clean Energy Benefit [1]				$ (85.06)			$ (101.04)	$ (15.98)	18.79%
Total Bill on TOU (including OCEB)				**$ 765.58**			**$ 909.41**	**$ 143.83**	**18.79%**

Loss Factor (%) 4.48% 3.42%

Customer Class: **General Service 1,000 to 4,999 kW**

Consumption 2000 **kW** ○ May 1 - October 31 ◉ 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	$ 2,794.5500	1	$ 2,794.55	$ 2,846.3200	1	$ 2,846.32	$ 51.77	1.85%
Distribution Volumetric Rate	per kW	$ 2.2314	2000	$ 4,462.80	$ 2.2619	2000	$ 4,523.80	$ 61.00	1.37%
Sub-Total A				$ 7,257.35			$ 7,370.12	**$ 112.77**	**1.55%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (0.7755)	2000	$ (1,551.00)	$ (1.3230)	2000	$ (2,646.00)	$ (1,095.00)	70.60%
Global Adjustment Rate Rider	per kW	$ (0.0924)	2000	$ (184.80)	$ 0.7057	2000	$ 1,411.40	$ 1,596.20	(863.74%)
Tax Charge Rate Rider	per kW	$ (0.0371)	2000	$ (74.20)	$ -	2000	$ -	$ 74.20	(100.00%)
GEA Funding Adder	Monthly				$ 0.0022	1	$ 0.00	$ 0.00	
Smart Meter Entity Charge						2000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5,447.35**			**$ 6,135.52**	**$ 688.17**	**12.63%**
RTSR - Network	per kW	$ 2.5777	2090	$ 5,386.36	$ 2.5597	2068	$ 5,294.48	$ (91.88)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.9295	2090	$ 4,031.88	$ 1.9093	2068	$ 3,949.20	$ (82.69)	(2.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 14,865.60**			**$ 15,379.20**	**$ 513.61**	**3.46%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	2090	$ 10.87	$ 0.0052	2068	$ 10.76	$ (0.11)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	2090	$ 2.30	$ 0.0011	2068	$ 2.28	$ (0.02)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	2090	$ 14.63	$ 0.0070	2068	$ 14.48	$ (0.15)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1000	$ 87.00	$ 0.0870	1000	$ 87.00	$ -	0.00%
TOU - Off Peak	per kW	$ 0.0630	1337	$ 84.25	$ 0.0630	1324	$ 83.40	$ (0.85)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	376	$ 37.24	$ 0.0990	372	$ 36.86	$ (0.38)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	376	$ 44.38	$ 0.1180	372	$ 43.93	$ (0.45)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 15,054.64**			**$ 15,567.96**	**$ 513.32**	**3.41%**
HST		13%		$ 1,957.10	13%		$ 2,023.83	$ 66.73	3.41%
Total Bill (including HST)				$ 17,011.74			$ 17,591.80	$ 580.06	3.41%
Ontario Clean Energy Benefit [1]				$ (1,701.17)			$ (1,759.18)	$ (58.01)	3.41%
Total Bill on RPP (including OCEB)				**$ 15,310.57**			**$ 15,832.62**	**$ 522.05**	**3.41%**
Total Bill on TOU (before Taxes)				**$ 15,059.51**			**$ 15,571.15**	**$ 511.64**	**3.40%**
HST		13%		$ 1,957.74	13%		$ 2,024.25	$ 66.51	3.40%
Total Bill (including HST)				$ 17,017.25			$ 17,595.40	$ 578.16	3.40%
Ontario Clean Energy Benefit [1]				$ (1,701.72)			$ (1,759.54)	$ (57.82)	3.40%
Total Bill on TOU (including OCEB)				**$ 15,315.53**			**$ 15,835.86**	**$ 520.34**	**3.40%**

Loss Factor (%) 4.48% 3.42%

Customer Class: **Umetered Scattered Load**

Consumption 150 **kWh** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after Oc

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 8.9100	1	$ 8.91	$ 7.0300	1	$ 7.03	$ (1.88)	(21.10%)
Distribution Volumetric Rate	per kWh	$ 0.0130	150	$ 1.95	$ 0.0103	150	$ 1.55	$ (0.41)	(20.77%)
Sub-Total A				$ 10.86			$ 8.58	**$ (2.29)**	**(21.04%)**
Deferral/Variance Account Disposition Rate Rider	per kWh	$ (0.0044)	150	$ (0.66)	$ (0.0036)	150	$ (0.54)	$ 0.12	(18.18%)
Tax Charge Rate Rider	per kWh	$ (0.0005)	150	$ (0.08)	$ -	150	$ -	$ 0.08	(100.00%)
Smart Meter Entity Charge					$ -	150	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 10.13**			**$ 8.04**	**$ (2.09)**	**(20.64%)**
RTSR - Network	per kWh	$ 0.0061	157	$ 0.96	$ 0.0061	155	$ 0.95	$ (0.01)	(1.01%)
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	157	$ 0.72	$ 0.0046	155	$ 0.71	$ (0.01)	(1.01%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 11.80**			**$ 9.69**	**$ (2.11)**	**(17.85%)**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	157	$ 0.81	$ 0.0052	155	$ 0.81	$ (0.01)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	157	$ 0.17	$ 0.0011	155	$ 0.17	$ (0.00)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	157	$ 1.10	$ 0.0070	155	$ 1.09	$ (0.01)	(1.01%)
Energy - RPP - Tier 1	per kWh	$ 0.0740	150	$ 11.10	$ 0.0740	150	$ 11.10	$ -	0.00%
Energy - RPP - Tier 2	per kWh	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kWh	$ 0.0630	100	$ 6.32	$ 0.0630	99	$ 6.25	$ (0.06)	(1.01%)
TOU - Mid Peak	per kWh	$ 0.0990	28	$ 2.79	$ 0.0990	28	$ 2.76	$ (0.03)	(1.01%)
TOU - On Peak	per kWh	$ 0.1180	28	$ 3.33	$ 0.1180	28	$ 3.29	$ (0.03)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 25.24**			**$ 23.11**	**$ (2.13)**	**(8.43%)**
HST		13%		$ 3.28	13%		$ 3.00	$ (0.28)	(8.43%)
Total Bill (including HST)				$ 28.52			$ 26.11	$ (2.40)	(8.43%)
Ontario Clean Energy Benefit [1]				$ (2.85)			$ (2.61)	$ 0.24	(8.42%)
Total Bill on RPP (including OCEB)				**$ 25.67**			**$ 23.50**	**$ (2.16)**	**(8.43%)**
Total Bill on TOU (before Taxes)				**$ 26.58**			**$ 24.32**	**$ (2.25)**	**(8.48%)**
HST		13%		$ 3.45	13%		$ 3.16	$ (0.29)	(8.48%)
Total Bill (including HST)				$ 30.03			$ 27.48	$ (2.55)	(8.48%)
Ontario Clean Energy Benefit [1]				$ (3.00)			$ (2.75)	$ 0.25	(8.33%)
Total Bill on TOU (including OCEB)				**$ 27.03**			**$ 24.73**	**$ (2.30)**	**(8.50%)**
Loss Factor (%)		4.48%			3.42%				

Customer Class: **Sentinel Lighting**

Consumption 0.2 **kW** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after O

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 6.4000	1	$ 6.40	$ 6.9400	1	$ 6.94	$ 0.54	8.44%
Distribution Volumetric Rate	per kW	$ 5.1350	0.2	$ 1.03	$ 5.5716	0.2	$ 1.11	$ 0.09	8.50%
Sub-Total A				$ 7.43			$ 8.05	**$ 0.63**	**8.45%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (2.4061)	0.2	$ (0.48)	$ 1.6015	0.2	$ 0.32	$ 0.80	(166.56%)
Tax Charge Rate Rider	per kW	$ (0.4698)	0.2	$ (0.09)		0.2	$ -	$ 0.09	(100.00%)
Smart Meter Entity Charge						0.2	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.85**			**$ 8.37**	**$ 1.52**	**22.22%**
RTSR - Network	per kW	$ 1.8420	0	$ 0.38	$ 1.8291	0	$ 0.38	$ (0.01)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.3779	0	$ 0.29	$ 1.3635	0	$ 0.28	$ (0.01)	(2.05%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.52**			**$ 9.03**	**$ 1.51**	**20.07%**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	0	$ 0.00	$ 0.0052	0	$ 0.00	$ (0.00)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	0	$ 0.00	$ 0.0011	0	$ 0.00	$ (0.00)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	0	$ 0.00	$ 0.0070	0	$ 0.00	$ (0.00)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	0	$ 0.01	$ 0.0740	0	$ 0.01	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak	per kW	$ 0.0630	0	$ 0.01	$ 0.0630	0	$ 0.01	$ (0.00)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	0	$ 0.00	$ 0.0990	0	$ 0.00	$ (0.00)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	0	$ 0.00	$ 0.1180	0	$ 0.00	$ (0.00)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 7.79**			**$ 9.30**	**$ 1.51**	**19.38%**
HST		13%		$ 1.01	13%		$ 1.21	$ 0.20	19.38%
Total Bill (including HST)				$ 8.81			$ 10.51	$ 1.71	19.38%
Ontario Clean Energy Benefit [1]				$ (0.88)			$ (1.05)	$ (0.17)	19.32%
Total Bill on RPP (including OCEB)				**$ 7.93**			**$ 9.46**	**$ 1.54**	**19.39%**
Total Bill on TOU (before Taxes)				**$ 7.79**			**$ 9.30**	**$ 1.51**	**19.38%**
HST		13%		$ 1.01	13%		$ 1.21	$ 0.20	19.38%
Total Bill (including HST)				$ 8.81			$ 10.51	$ 1.71	19.38%
Ontario Clean Energy Benefit [1]				$ (0.88)			$ (1.05)	$ (0.17)	19.32%
Total Bill on TOU (including OCEB)				**$ 7.93**			**$ 9.46**	**$ 1.54**	**19.38%**

Loss Factor (%) 4.48% 3.42%

Customer Class: **Street Lighting**

Consumption **2400** **kW** ○ May 1 - October 31 ◉ 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	$ 2.1600	1	$ 2.16	$ 1.1600	1	$ 1.16	$ (1.00)	(46.30%)
Distribution Volumetric Rate	per kW	$ 13.0610	2400	$ 31,346.40	$ 6.9908	2400	$ 16,777.92	$ (14,568.48)	(46.48%)
Sub-Total A				$ 31,348.56			$ 16,779.08	**$ (14,569.48)**	**(46.48%)**
Deferral/Variance Account Disposition Rate Rider	per kW	$ (1.5474)	2400	$ (3,713.76)	$ (1.3308)	2400	$ (3,193.92)	$ 519.84	(14.00%)
Tax Charge Rate Rider	per kW	$ (0.2863)	2400	$ (687.12)	$ -	2400	$ -	$ 687.12	(100.00%)
Smart Meter Entity Charge						2400	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26,947.68**			**$ 13,585.16**	**$ (13,362.52)**	**(49.59%)**
RTSR - Network	per kW	$ 1.8325	2508	$ 4,595.03	$ 1.8197	2482	$ 4,516.64	$ (78.39)	(1.71%)
RTSR - Line and Transformation Connection	per kW	$ 1.3496	2508	$ 3,384.15	$ 1.3354	2482	$ 3,314.57	$ (69.58)	(2.06%)
Sub-Total C - Delivery (including Sub-Total B)				**$ 34,926.86**			**$ 21,416.37**	**$ (13,510.49)**	**(38.68%)**
Wholesale Market Service Charge (WMSC)	per kW	$ 0.0052	2508	$ 13.04	$ 0.0052	2482	$ 12.91	$ (0.13)	(1.01%)
Rural and Remote Rate Protection (RRRP)	per kW	$ 0.0011	2508	$ 2.76	$ 0.0011	2482	$ 2.73	$ (0.03)	(1.01%)
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kW	$ 0.0070	2508	$ 17.55	$ 0.0070	2482	$ 17.37	$ (0.18)	(1.01%)
Energy - RPP - Tier 1	per kW	$ 0.0740	1000	$ 74.00	$ 0.0740	1000	$ 74.00	$ -	0.00%
Energy - RPP - Tier 2	per kW	$ 0.0870	1400	$ 121.80	$ 0.0870	1400	$ 121.80	$ -	0.00%
TOU - Off Peak	per kW	$ 0.0630	1605	$ 101.10	$ 0.0630	1589	$ 100.08	$ (1.03)	(1.01%)
TOU - Mid Peak	per kW	$ 0.0990	451	$ 44.68	$ 0.0990	447	$ 44.23	$ (0.45)	(1.01%)
TOU - On Peak	per kW	$ 0.1180	451	$ 53.26	$ 0.1180	447	$ 52.72	$ (0.54)	(1.01%)
Total Bill on RPP (before Taxes)				**$ 35,156.26**			**$ 21,645.43**	**$ (13,510.83)**	**(38.43%)**
HST		13%		$ 4,570.31	13%		$ 2,813.91	$ (1,756.41)	(38.43%)
Total Bill (including HST)				$ 39,726.57			$ 24,459.34	$ (15,267.23)	(38.43%)
Ontario Clean Energy Benefit [1]				$ (3,972.66)			$ (2,445.93)	$ 1,526.73	(38.43%)
Total Bill on RPP (including OCEB)				**$ 35,753.91**			**$ 22,013.41**	**$ (13,740.50)**	**(38.43%)**
Total Bill on TOU (before Taxes)				**$ 35,159.51**			**$ 21,646.66**	**$ (13,512.85)**	**(38.43%)**
HST		13%		$ 4,570.74	13%		$ 2,814.07	$ (1,756.67)	(38.43%)
Total Bill (including HST)				$ 39,730.24			$ 24,460.73	$ (15,269.52)	(38.43%)
Ontario Clean Energy Benefit [1]				$ (3,973.02)			$ (2,446.07)	$ 1,526.95	(38.43%)
Total Bill on TOU (including OCEB)				**$ 35,757.22**			**$ 22,014.66**	**$ (13,742.57)**	**(38.43%)**

Loss Factor (%) 4.48% 3.42%

Customer Class: **Microfit**

Consumption 5 **kW** ○ May 1 - October 31 ◉ November 1 - April 30 (Select this radio button for applications filed after O

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 5.2500	1	$ 5.25	$ 5.4000	1	$ 5.40	$ 0.15	2.86%
Sub-Total A				$ 5.25			$ 5.40	**$ 0.15**	**2.86%**
			5	$ -		5	$ -	$ -	
			5	$ -		5	$ -	$ -	
						5	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
RTSR - Network			5	$ -		5	$ -	$ -	
RTSR - Line and Transformation Connection			5	$ -		5	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
Wholesale Market Service Charge (WMSC)			5	$ -		5	$ -	$ -	
Rural and Remote Rate Protection (RRRP)			5	$ -		5	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)			5	$ -		5	$ -	$ -	
Energy - RPP - Tier 1			5	$ -		5	$ -	$ -	
Energy - RPP - Tier 2			0	$ -		0	$ -	$ -	
TOU - Off Peak			3	$ -		3	$ -	$ -	
TOU - Mid Peak			1	$ -		1	$ -	$ -	
TOU - On Peak			1	$ -		1	$ -	$ -	
Total Bill on RPP (before Taxes)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
HST		13%		$ 0.68	13%		$ 0.70	$ 0.02	2.86%
Total Bill (including HST)				$ 5.93			$ 6.10	$ 0.17	2.86%
Ontario Clean Energy Benefit [1]				-$ 0.59			-$ 0.61	-$ 0.02	3.39%
Total Bill on RPP (including OCEB)				**$ 5.34**			**$ 5.49**	**$ 0.15**	**2.80%**
Total Bill on TOU (before Taxes)				**$ 5.25**			**$ 5.40**	**$ 0.15**	**2.86%**
HST		13%		$ 0.68	13%		$ 0.70	$ 0.02	2.86%
Total Bill (including HST)				$ 5.93			$ 6.10	$ 0.17	2.86%
Ontario Clean Energy Benefit [1]				-$ 0.59			-$ 0.61	-$ 0.02	3.39%
Total Bill on TOU (including OCEB)				**$ 5.34**			**$ 5.49**	**$ 0.15**	**2.80%**

Loss Factor (%) 4.48% 3.42%

Exhibit	Tab	Schedule	Appendix	Contents
9 – Deferral and Variance Accounts				
	1	1		Overview
		2		Previous Deferral/Variance Account Disposition
	2	1		Status of Deferral and Variance Accounts
		2		Account Balances
		3		Accounts Requested for Disposition by way of a Deferral and Variance Account Rate Rider
		4		Method of Disposition
		5		Deferral and Variance Accounts Requested
	3	1		Stranded Meter Costs
	4	1		Green Energy Plan – Funding Adder
	5	1		LRAM Recovery

OVERVIEW

DEFERRAL AND VARIANCE ACCOUNTS

The information contained in this exhibit includes the status and description of Thunder Bay Hydro's deferral and variance accounts, the proposed disposition of certain account balances, and the rate riders required for recovery or refund of the account balances.

PREVIOUS DEFERRAL / VARIANCE ACCOUNT DISPOSITION

2012 Smart Meter Funding and Cost Recovery – Final Disposition

On July 5, 2012, the Ontario Energy Board's Decision and Order EB-2012-0115 approved a two-year disposition rate rider for the Smart Meter Disposition balance in the amount of ($1,136,137) to be refunded and a Smart Meter Incremental Revenue Rate Rider to be collected over one year in the amount of $1,364,127. In 2012, the approved balances were transferred from the deferral accounts 1555 and 1556 to the corresponding capital and OM&A accounts.

2012 IRM Disposition

On April 4, 2012 the Ontario Energy Board's Decision and Order EB-2011-0197 approved a one year disposition of Group 1 account balances as of December 31, 2010, effective May 1, 2012. The account balances were transferred to account 1595 and rates for disposition are approved until April 30, 2013.

In the same application, the Board approved, on a final basis, the disposition of a debit balance of $34,737 in Account 1521 Special Purpose Charge ("SPC"). In 2012, the approved balance was transferred to a sub-account of 1595 over a one year period.

Also, in the 2012 IRM decision, the Board approved the disposition of the credit balance in Account 1562 Deferred Payments in Lieu of Taxes ("PILs") of $785,990, on a final basis over a one year period.

2011 IRM Disposition

On March 28, 2011 the Board's Decision and Order EB-2010-0115 approved a one year disposition of Group 1 account balances as of December 31, 2009, effective May 1, 2011. The account balances were transferred to account 1595 and rates for disposition were approved until April 30, 2012.

2010 IRM Disposition

On March 28, 2011 the Board's Decision and Order EB-2009-0250 approved a one year disposition of Group 1 account balances as of December 31, 2008, effective May 1, 2010. The account balances were transferred to account 1595 and rates for disposition were approved until April 30, 2011.

STATUS OF DEFERRAL AND VARIANCE ACCOUNTS

This Schedule contains the status of Deferral and Variance Accounts ("DVAs") currently used by Thunder Bay Hydro. The balances as at December 31, 2011 and the proposed recovery amounts are summarized in Table 9-2.1 following the descriptions of each account. Thunder Bay Hydro confirms that is has used all deferral and variance accounts and sub-accounts as described in the APH.

GROUP 1 ACCOUNTS

1580 Retail Settlement Variance Account - Wholesale Market Service Charges

This account is used to record the net of the amount charged by the IESO based on the settlement invoice for the operation of the IESO-administered markets and the operation of the IESO-controlled grid, and the amount billed to customers using the OEB-approved Wholesale Market Service Rate. Thunder Bay Hydro uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1580. The requested amount is a credit of ($1,470,667).

1584 Retail Settlement Variance Account - Retail Transmission Network Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission network services, and the amount billed to customers using the OEB-approved Retail Transmission Rate for network services. Thunder Bay Hydro uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1584. The requested amount is a credit of ($244,701).

1586 Retail Settlement Variance Account - Retail Transmission Connection Charges

This account is used to record the net of the amount charged by the IESO, based on the settlement invoice for transmission connection services, and the amount billed to customers using the OEB-approved Retail Transmission Rate for connection services. Thunder Bay Hydro uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1586. The requested amount is a credit of ($436,592).

1588 Retail Settlement Variance Account – Power (excluding Global Adjustment)

This account is used to recover the net difference between the energy amount billed to customers and the energy charge to Thunder Bay Hydro using the settlement invoice from the Independent Electricity System Operator (IESO). Thunder Bay Hydro uses the accrual method. The variance between Board-approved and actual line losses is reflected in Account 1588 for the applicable period. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1588 - Power. The requested amount is a credit of ($1,203,459).

1588 Retail Settlement Variance Account - Power, Sub-account Global Adjustment

This account is used to recover the net difference between the provincial benefit amount billed to non-RPP customers and the global adjustment charge to Thunder Bay Hydro using the settlement invoice from the IESO. Thunder Bay Hydro uses the accrual method. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

For 2013, Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1588 sub account Global Adjustment through a separate non-RPP rate rider. The requested amount is a debit of $1,022,422.

1590 Recovery of Regulatory Asset Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recovery. Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1590 in the amount of a debit balance of $11.

1595 Disposition and Recovery of Regulatory Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recovery.

Sub-Account 2008 for EB-2008-0245

In accordance with the OEB EB-2008-0245 Decision and Order for Thunder Bay Hydro's 2009 COS Application, the December 31, 2007 credit balance of ($2,139,323) including interest forecast to April 30, 2009 was transferred to a sub-account of 1595 in April 2009. This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recovery. The recovery period ended April 30, 2011 and the residual balance has been audited. Thunder Bay Hydro is requesting recovery of the credit balance of ($38,086) as at December 31, 2011 including forecasted carrying charges to April 30, 2013.

Sub-Account 2009 for EB-2009-0250

In accordance with the OEB EB-2009-0250 Decision and Order for Thunder Bay Hydro's 2010 IRM, the December 31, 2008 credit balance of ($1,025,804) including interest forecasted to April 30, 2010 was transferred to a sub-account of 1595 in April 2010. Thunder Bay Hydro was further ordered to record the shared tax savings resulting from the Ontario Capital Tax rate decrease for 2010. The credit balance of ($106,032) was recorded in the sub-account of 1595 for disposition at a future rate proceeding. The

recovery period ended April 30, 2011 and the residual balance has been audited. Thunder Bay Hydro is requesting recovery of the credit balance of ($118,956) as at December 31, 2011 including forecasted carrying charges to April 30, 2013.

Sub-Account 2010 for EB-2010-0115

In accordance with the OEB EB-2010-0115 Decision and Order for Thunder Bay Hydro's 2011 IRM, the December 31, 2009 debit balance of $2,725,159, including interest forecast to April 30, 2011 was transferred to a sub-account of 1595 in April 2011. As of April 30, 2012 the disposition period for Group 1 balances was completed, however, Thunder Bay Hydro is not requesting disposition of the residual balance in this sub-account as the balance has not been audited.

GROUP 2 ACCOUNTS

1508 Other Regulatory Assets - Sub-account OEB Cost Assessments

This account includes amounts paid for OEB Cost Assessment for the period January 1, 2005 to April 30, 2006 in excess of amounts previously included in rates (1999 OEB costs). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1508 – Sub-account OEB Cost Assessments. The requested amount is a debit of $121.

1508 Other Regulatory Assets - Sub-account Pension Contributions

This account includes amounts paid for OMERS pension expense for the period January 1, 2005 to April 30, 2006 not included in rates. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1508 – Sub-account Pension Contributions. The requested amount is a debit of $474.

1508 Other Regulatory Assets – Sub-account IFRS Transition Costs

This account includes amounts paid for one-time incremental costs for the transition to International Financial Reporting Standards (IFRS). The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Thunder Bay Hydro has established account 1508 – sub account IFRS Transition Costs in accordance with the Board Requirements. In the Board's Accounting Procedures Handbook Frequently Asked Questions October 2009 ("APH-FAQ October 2009"), the Board permitted the deferral of one-time administrative costs caused by the transition of accounting policies, procedures, systems, and processes to International Financial Reporting Standards ("IFRS") in this sub-account. Also in the Board's Accounting Procedures Handbook Frequently Asked Questions October 2009 ("APH-FAQ October 2009"), the Board permitted interest carrying charges to be calculated on the monthly opening principal balance of this sub-account at the Board's prescribed interest rates. Based on this guidance, Thunder Bay Hydro commenced to defer professional accounting fees, incremental salaries, wages, and benefits of staff attributable to the transition to IFRS, staff training costs solely related to IFRS, actuarial services and carrying charges solely related to these items.

The balance as of December 31, 2011 plus projected interest is a debit amount of $52,292; however the account balance represents approximately 50% of what has been forecasted for 2012. Anticipated costs required to complete conversion to IFRS include incremental costs associated with converting Thunder Bay Hydro's fixed asset sub ledger and capitalization process to be compliant with IFRS and assistance with financial statement conversion upon adoption of IFRS. Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance and to keep the sub-account open and request disposition of additional balances at its next Cost of Service Application.

Table 9-2.1 Details the One-Time Incremental IFRS Transition Costs and carrying charges up to December 31, 2011 as set out in Thunder Bay Hydro's audited financial statements and as set out in the April 30, 2012 RRR 2.1.7 Schedule.

Table 9-2.1 - One-Time Incremental IFRS Transition Costs and carrying charges

Nature of One-Time Incremental IFRS Transition Costs [1]	Audited Actual Costs Incurred 2009	Audited Actual Costs Incurred 2010	Audited Actual Costs Incurred 2011	Audited Carrying Charges to Dec 31, 2011	Total Audited Actual Costs to Dec 31, 2011	RRR 2.1.7 Balance 31-Dec-11	Variance [2]	Reasons why the costs recorded meet the criteria of one-time IFRS administrative incremental costs
Professional accounting fees			6,774	68	6,842			Fees associated with transitional analysis for fixed assets and draft IFRS compliant financial statements
Professional legal fees					-			
Salaries, wages and benefits of staff added to support the transition to IFRS			12,386	125	12,511			Staff support with updating financial records for IFRS compliance and conversion from GAAP
Associated staff training and development costs	5,640	2,598	13,846	140	22,224			Training costs for IFRS transition
Costs related to system upgrades, or replacements or changes where IFRS was the major reason for			8,620	87	8,707			Software upgrades and training (transition of subledger)
Professional actuarial/consulting services			1,000	10	1,010			Fees associated with actuarial services
					-			
					-			
					-			
					-			
					-			
					-			
Insert description of additional item(s) and new rows if					-			
Total	5,640	2,598	42,626	431	51,295	51,890	(595)	Variance due to debit balances of OEB cost assessment $120 and pension contributions $475 that are other sub-accounts of 1508

The largest component of the costs included in this account relate to training and development costs used to prepare the documentation of Thunder Bay Hydro's new policies, procedures and process flows as a result of implementing IFRS. There were also costs included in this account for incremental labour costs of staff to work on the IFRS project and training. These costs would not have been incurred if Thunder Bay Hydro had not been required to transition to IFRS.

Thunder Bay Hydro confirms that no capital costs, ongoing IFRS compliance costs, or impacts arising from adopting accounting policy charges are recorded in the Deferred IFRS Transition Costs Account.

1518 Retail Settlement Variance Account – Retail

This account is used to recover the net differences between the revenues recovered from Retailer Service Agreements and Billing options and the cost of managing the retailer contracts. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1518 – RCVA Retail. The requested amount is a debit of $148,737.

1548 Retail Settlement Variance Account – Service Transaction Request

This account is used to recover the net differences between the revenues recovered from Service Transaction Requests and the incremental costs of providing these services.

The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

Thunder Bay Hydro is requesting disposition of the December 31, 2011 audited balance plus the forecasted interest through April 30, 2013 for account 1548 – RCVA STR. The requested amount is a debit of $137,892.

1555 Smart Meter Capital and Recoveries – Sub-Accounts

Amounts recorded in this account include the revenues from smart meter adders approved by the Board for smart meters and related capital costs incurred by Thunder Bay Hydro. On July 5, 2012 the Ontario Energy Board's Decision and Order EB-2012-0015 approved the disposition of this account on a final basis. The corresponding rate rider is effective until April 30, 2014. In 2012, the approved balance was transferred to the corresponding revenue and capital accounts.

1556 Smart Meter OM&A Variance Account

This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. On July 5, 2012, the Ontario

Energy Board's Decision and Order EB-2012-0015 approved the disposition of this account on a final basis. The corresponding rate rider is effective until April 30, 2014. In 2012, the approved balances were transferred to the corresponding OM&A accounts.

1562 Deferred Payments in Lieu of Taxes

This account records the amount resulting from the Board approved PILs methodology for determining the 2001 Deferral Account Allowance and the PILs proxy amount determined for 2002 and subsequent years. The amount determined using the Board approved PILs methodology is recorded equally over the applicable PILs period. The 2001 PILs Deferral Account Allowance is recorded in three equal installments in October, November and December since December 31, 2001 is the taxation year end. For a full year each applicable proxy is divided by 12, and a monthly amount is posted for each applicable period.

In accordance with the Decision and Order dated April 4, 2012, Thunder Bay Hydro was ordered to transfer the balance of Account 1562 to the principal and interest carrying charge sub-accounts of Account 1595. Thunder Bay Hydro has transferred a credit balance in Account 1562 Deferred Payments in Lieu of Taxes ("PILs") of $785,990, on a final basis to be paid over a one year period to its customers.

1568 LRAM Variance Account

This account includes the lost revenue adjustment mechanism ("LRAM") variances in relation to the conservation and demand management ("CDM") programs or activities undertaken by Thunder Bay Hydro in accordance with Board- prescribed requirements. Thunder Bay Hydro is requesting disposition of a debit amount of $40,315. More detail in regards to the LRAM claim can be found in the LRAM Recovery section below.

1592 PILs and Tax Variance for 2006 and Subsequent Years – Sub-account HST/OVAT Input Tax Credits (ITC's)

This account is used to record the incremental ITC received on distribution revenue requirement items that were previously subject to PST and which now become subject to HST. Tracking of these amounts will continue in this deferral account until the effective date of Thunder Bay Hydro's next cost of service rate order. Fifty percent (50%) of the confirmed balance in this account shall be returnable to the ratepayers.

Account 1592 – Sub-account HST includes a credit balance of ($181,342) which represents 100% of the HST balance as at December 31, 2011. For 2013, Thunder Bay Hydro is requesting 50% disposition of the December 31, 2011 audited balance plus forecasted interest of ($3,527) from January 1, 2012 through to April 30, 2013 for a total of ($184,868). The requested amount is a credit balance of ($92,434). This is shown in Table 9-2.2.

Table 9-2.2 - Deferred PILs Account 1592 Balances

Tax Item	Principal as of December 31, 2011
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007	
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4/12ths of the approved grossed-up proxy), if not recorded in PILs account 1562	
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	
Capital Cost Allowance class changes from 2006 EDR application for 2006	
Capital Cost Allowance class changes from 2006 EDR application for 2007	
Capital Cost Allowance class changes from 2006 EDR application for 2008	
Capital Cost Allowance class changes from 2006 EDR application for 2009	
Capital Cost Allowance class changes from 2006 EDR application for 2010	
Capital Cost Allowance class changes from 2006 EDR application for 2011	
PILs Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs) - Represents 100% of the account balances as at December 31, 2011	(179,928)
Carrying Charges as at Dec. 31, 2011	(1,414)
Carrying Charges calculated from Jan. 1/12 to April 30/13	(3,527)
Subtotal	(184,868)
To be refunded back to customers (50%)	**(92,434)**

As indicated in the table above, the only type of tax item in Account 1592 is the ITCs that have been deferred starting July 1, 2010 through to December 31, 2011, thus, the guidance provided in the FAQ of July, 2007 is not applicable to Thunder Bay Hydro.

In accordance with the filing requirements, Thunder Bay Hydro has revised the deferral and variance account continuity schedule to include account 1592 as a Group 2 account and has recorded the above-noted amounts therein.

Table 9-2.3 below, shows the HST savings each year including carrying charges and also the total applicable spending within OM&A and capital that was captured in the ITC calculations.

Table 9-2.3 - HST Savings by Year

	2010 Actual HST Savings	2011 Actual HST Savings	Total	Jan. 1/12 to Apr. 30/13 Interest	Grand Total
OM&A	33,690	135,134	168,824		168,824
Capital	1,443	9,661	11,104		11,104
Total	35,133	144,795	179,928		179,928
Interest	64	1,350	1,414	3,527	4,941
Total HST Savings	35,197	146,145	181,342		184,868
50% Refund to Customers					92,434

Actuals purchases			
OM&A	421,127	1,689,175	2,110,302
Capital	644,069	2,000,993	2,645,062
Total	1,065,196	3,690,168	4,755,363

In the December 2010 FAQ response to Q#1, the Board directed distributors to record the ITCs in Account 1592 with the offsetting entry to be recorded in a new sub-account that will serve as a contra account. For regulatory reporting purposes, this will have a zero net effect on reporting. Only the balance in “Sub-account HST / OVAT Input Tax Credits (ITCs)” should be reported for disposition of the account balance, except for purposes of reporting under the Electricity Reporting & Record Keeping Requirements, which should include both sub-accounts netting to zero.

Table 9-2.4 below, shows a reconciliation of Account 1592 between the 2011 RRR 2.1.7, the Audited Financial Statements, and the Continuity Schedule in which the only variance item being the contra sub-account not being reported on the Continuity Schedule.

Table 9-2.4 -Reconciliation of Account 1592

Account 1592 as at December 31, 2011

	A	B	C	B-A	C-A
	2011 RRR 2.1.7	**Audited Financial Statements**	**Continuity Schedule**	**Variance**	**Variance**
HST Deferral sub-account	(181,342)	-	(90,671)	181,342	90,671
HST Deferral sub-account contra	181,342	-	-	(181,342)	(181,342)
Total	-	-	(90,671)	-	(90,671)

As noted above, Thunder Bay Hydro has recorded variances on a monthly basis in the sub-account of Account 1592 to cover the period starting July 1, 2010 and will continue to do so until April 30, 2013, with May 1, 2013 being the start of the Test Year. In regards to the methodology of calculating the ITCs, Thunder Bay Hydro sought to adhere to the Board's Decision and Order in EB-2009-0250 to start recording the ITCs in deferral account 1592 beginning July 1, 2010. Although requested prior to this commencement date, guidance on a simplified method was not provided until the Board's December 2010 FAQ, particularly Question #4. As a result, Thunder Bay Hydro opted to calculate the ITCs on a transactional basis.

Thunder Bay Hydro developed a process to calculate the HST savings for 3 major groups of costs: OM&A expenses; inventory purchases; and capital purchases. At the onset of developing the process, a list of applicable transactions that were previously subject to PST but charged HST post July 1, 2010 was developed and all accounts within the general ledger that included these applicable transactions were identified. The methodology used for each of the major groups is discussed further below.

In calculating the OM&A ITCs on a monthly basis, Thunder Bay Hydro reviews all transactions that occurred in the applicable accounts on a monthly basis to calculate the ITCs. Every transaction is reviewed since there may be a specific purchase that would not qualify as an applicable transaction (ie) was not subject to PST prior to July 1, 2010. The calculation for each transaction for the ITC is as follows:

(Purchase amount * 0.13) * 8%/13%

In calculating the ITCs on inventory purchases, Thunder Bay Hydro first considered that purchases up to June 30, 2010 would include PST and therefore should not be considered in the ITCs. The first-in-first-out ("FIFO") inventory method has been applied such that inventories issued post July 1, 2010 but purchased pre July 1, 2010 would not be considered in the ITC calculations. A report is run to show the inventory issues on a monthly basis and for those purchases post July 1, 2010, the issues are split between capital, recoverable, and OM&A materials. The capital issues are included in the capital analysis as discussed next, recoverables are excluded from the ITC calculation since the customer is charged for the material, and OM&A issues are included in the OM&A transactions.

For capital purchases post July 1, 2010, Thunder Bay Hydro analyses each purchase within the applicable accounts identified as potentially being included in the ITC calculation on a monthly basis. The monthly ITC amount is determined as follows:

((Purchase amount * 0.13) * 8%/13%) / useful life in years / 12 months

The calculated amount for each purchase above is brought forward in the monthly ITC amount until April 30, 2013.

Please note that carrying charges are calculated on the opening monthly net principal balance using the Board's prescribed interest rate.

The accounting entry to post the ITC on a monthly basis as follows:

Debit 1592 Sub-account HST/OVAT ITCs - OM&A Contra
Debit 1592 Sub-account HST/OVAT ITCs – Capital Contra
Debit 1592 Sub-account HST/OVAT ITCs - Carrying Charges Contra

Credit 1592 Sub-account HST/OVAT ITCs - OM&A
Credit 1592 Sub-account HST/OVAT ITCs - Capital
Credit 1592 Sub-account HST/OVAT ITCs - Carrying Charges

Thunder Bay Hydro requests leave to discontinue tracking HST/OVAT/ITC as at April 30, 2013. Thunder Bay Hydro also requests the Board to allow Account 1592 remain open, pending Board approval to discontinue tracking costs effective April 30, 2013 and until such time as Thunder

Bay Hydro files its 2014 IRM rate application at which time Thunder Bay Hydro will apply to the Board for an order to clear any audited debit or credit balance remaining in Account 1592.

ACCOUNT BALANCES

The following Table 9-.2.5 contains account balances from the 2011 Audited Financial Statements as at December 31, 2011 and agrees to the 2011 year end balances for RRR filing E2.1.7 Trial Balance as filed April 30, 2012 with the OEB.

Table 9-2.5 - December 31, 2011 Audited Balances – Deferral and Variance Accounts

Group 1 Deferral / Variance Accounts		Principal	Interest	Total
1580	RSVA - Wholesale Market Service Charge	($2,490,129)	($31,724)	($2,521,853)
1584	RSVA - Retail Transmission Network Charge	($119,141)	$4,577	($114,564)
1586	RSVA - Retail Transmission Connection Charge	($417,879)	$5,398	($412,480)
1588	RSVA - Power (excluding Global Adjustment)	($2,179,141)	($22,083)	($2,201,224)
1588	RSVA - Power - Sub-account - Global Adjustment	$859,178	$5,628	$864,806
1590	Recovery of Regulatory Asset Balances	$8	($296)	($288)
1595	Disposition and Recovery/Refund of Regulatory Balances (2008)	$343,375	($388,191)	($44,816)
1595	Disposition and Recovery/Refund of Regulatory Balances (2009)	($306,957)	$194,017	($112,940)
Sub- Total		($4,310,686)	($232,673)	($4,543,359)
Group 2 Deferral / Variance Accounts		**Principal**	**Interest**	**Total**
1508	Other Regulatory Assets - Sub-Account - OEB Cost Assessments	$0	$121	$121
1508	Other Regulatory Assets - Sub-Account - Pension Contributions	$0	$474	$474
1508	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	$50,864	$431	$51,295
1518	Retail Cost Variance Account - Retail	$141,767	$4,191	$145,959
1548	Retail Cost Variance Account - STR	$131,141	$4,181	$135,322
1592	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	($89,964)	($707)	($90,671)
Sub-Total		$233,809	$8,690	$242,499
Group 1 & Group 2 Total		($4,076,878)	($223,983)	($4,300,861)

Please not that Account 1592 has a contra account, and thus, for OEB Reporting purposes and on the Audited Financial Statements the balance is $0. The above Table represents the 50% of the HST savings before being contraed, which is to be refunded back to Thunder Bay Hydro's customers.

Thunder Bay Hydro confirms that all of the above accounts will continue on a going forward basis unless otherwise directed by the Board.

Thunder Bay Hydro confirms that it has not made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis in both Cost of Service and IRM proceedings.

Table 9-2.6 provides the interest rates that have been used to calculate actual and forecast carrying charges on the accounts in accordance with the methodology approved by the Board in EB-2006-0117 on November 28, 2006.

Table 9.2.6 - Interest Rates Applied to Deferral and Variance Accounts

Quarter by Year	Prescribed Interest Rate
Q1 2005	7.25%
Q2 2005	7.25%
Q3 2005	7.25%
Q4 2005	7.25%
Q1 2006	7.25%
Q2 2006	4.14%
Q3 2006	4.59%
Q4 2006	4.59%
Q1 2007	4.59%
Q2 2007	4.59%
Q3 2007	4.59%
Q4 2007	5.14%
Q1 2008	5.14%
Q2 2008	4.08%
Q3 2008	3.35%
Q4 2008	3.35%
Q1 2009	2.45%
Q2 2009	1.00%
Q3 2009	0.55%
Q4 2009	0.55%
Q1 2010	0.55%
Q2 2010	0.55%
Q3 2010	0.89%
Q4 2010	1.20%
Q1 2011	1.47%
Q2 2011	1.47%
Q3 2011	1.47%
Q4 2011	1.47%
Q1 2012	1.47%
Q2 2012	1.47%
Q3 2012	1.47%
Q4 2012	1.47%

ACCOUNTS REQUESTED FOR DISPOSITION BY WAY OF A DEFERRAL AND VARIANCE ACCOUNT RATE RIDER

Thunder Bay Hydro is requesting disposition of the variance accounts noted below according to the Report of the Board EB-2009-0046, which states that "at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline.

Thunder Bay has followed the guidelines in the Report of the Board and requests disposition over a one-year period. Thunder Bay Hydro has provided a continuity schedule of the accounts listed below in the Excel Workbook named 2013_EDDVAR_Continuity_Schedule_CoS_v2_OEB submitted with this application.

Thunder Bay Hydro is requesting the disposition of the following Group 1 and Group 2 Accounts shown in Tables 9-2.7, 9-2.8, 9-2.9 and 9-2.10. These amounts are comprised of the audited balances as of December 31, 2011 and the forecasted interest through April 30, 2013.

Table 9-2.7 Group 1 Deferral / Variance Accounts – Excluding 1588 GA sub-account

Group 1 Deferral / Variance Accounts		Principal (Dec. 31/11)	Interest (Dec. 31/11)	Disposition in 2012 EB-2011-0197	Projected Interest to Dec. 31/12	Projected Interest to Apr. 30/13	Total
1580	RSVA - Wholesale Market Service Charge	($2,490,129)	($31,724)	$1,079,280	($21,070)	($7,023)	($1,470,667)
1584	RSVA - Retail Transmission Network Charge	($119,141)	$4,577	($125,419)	($3,539)	($1,180)	($244,701)
1586	RSVA - Retail Transmission Connection Charge	($417,879)	$5,398	($15,713)	($6,299)	($2,100)	($436,592)
1588	RSVA - Power (excluding Global Adjustment)	($2,179,141)	($22,083)	$1,020,940	($17,381)	($5,794)	($1,203,459)
1590	Recovery of Regulatory Asset Balances	$8	($296)	$299	$0	$0	$11
1595	Disposition and Recovery/Refund of Regulatory Balances (2008)	$343,375	($388,191)	$0	$5,048	$1,683	($38,086)
1595	Disposition and Recovery/Refund of Regulatory Balances (2009)	($306,957)	$194,017	$0	($4,512)	($1,504)	($118,956)
Total		($5,169,864)	($238,301)	$1,959,387	($47,754)	($15,918)	($3,512,450)

Table 9.2.8 Group 2 Deferral / Variance Accounts

Group 2 Deferral / Variance Accounts		Principal (Dec. 31/11)	Interest (Dec. 31/11)	Disposition in 2012 EB-2011-0197	Projected Interest to Dec. 31/12	Projected Interest to Apr. 30/13	Total
1508	Other Regulatory Assets - Sub-Account - OEB Cost Assessments	$0	$121	$0	$0	$0	$121
1508	Other Regulatory Assets - Sub-Account - Pension Contributions	$0	$474	$0	$0	$0	$474
1508	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	$50,864	$431	$0	$748	$249	$52,292
1518	Retail Cost Variance Account - Retail	$141,767	$4,191	$0	$2,084	$695	$148,737
1525	Misc. Deferred Debits	$0	$1	$0	$0	$0	$1
1548	Retail Cost Variance Account - STR	$131,141	$4,181	$0	$1,928	$643	$137,892

Table 9.2.9 1588 GA Sub-Account

		Principal (Dec. 31/11)	Interest (Dec. 31/11)	Disposition in 2012 EB-2011-0197	Projected Interest to Dec. 31/12	Projected Interest to Apr. 30/13	Total
1588	RSVA - Power - Sub-account - Global Adjustment	$859,178	$5,628	$138,091	$14,644	$4,881	$1,022,422

Thunder Bay Hydro confirms that the IESO Global Adjustment Charge has been pro-rated into the RPP and non-RPP portions.

Table 9.2.10 1568 LRAM Variance Account

		Principal (Dec. 31/11)	Interest (Dec. 31/11)	Disposition in 2012 EB-2011-0197	Projected Interest to Dec. 31/12	Projected Interest to Apr. 30/13	Total
1568	LRAM Variance Account	$39,255	$290	$0	$577	$192	$40,315

METHOD OF DISPOSITION

Allocators

Thunder Bay Hydro submits the following Allocators in Table 9-2.11 which are used to assign the Group 1 and Group 2 balances to rate each class. Please note that the billing determinants used is Thunder Bay Hydro's 2011 Actuals as filed in the 2011 RRR filing.

Table 9-2.11 – Allocation by Customer Class

Rate Class	Units	# of Customers	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion	1595 Recovery Share Proportion (2008)	1595 Recovery Share Proportion (2009)	1595 Recovery Share Proportion (2010)
Residential	kWh	44,749	337,828,768	-	33,772,368	-	$ 10,099,180	104%	0%	26%	27%
General Service Less Than 50 kW	kWh	4,485	135,513,010	-	20,388,898	-	$ 2,797,029	28%	0%	14%	12%
General Service 50 to 999 kW	kW	511	287,676,650	741,149	252,908,641	651,576	$ 2,448,809	40%	0%	33%	30%
General Service 1,000 to 4,999 kW	kW	20	182,011,908	518,430	189,511,114	539,790	$ 1,307,970	(69%)	0%	26%	30%
Unmetered Scattered Load	kWh	471	1,965,510	-	389,969	-	$ 126,649	0%	0%	0%	0%
Sentinel Lighting	kW	148	123,582	337	-	-	$ 13,497	0%	0%	0%	0%
Street Lighting	kW	13,075	11,244,633	31,834	11,700,787	33,125	$ 733,635	(3%)	0%	1%	1%
Total		**63,459**	**956,364,061**	**1,291,750**	**508,671,777**	**1,224,491**	**$ 17,526,769**	**100%**	**0%**	**100%**	**100%**

Rate Class	Units	# of Customers	Metered kWh	Metered kW	Billed kWh for Non-RPP Customers	Estimated kW for Non-RPP Customers	Distribution Revenue [1]	1590 Recovery Share Proportion	1595 Recovery Share Proportion (2008)	1595 Recovery Share Proportion (2009)	1595 Recovery Share Proportion (2010)
Residential	kWh	71%	35%	0%	7%	0%	58%	104%	0%	26%	27%
General Service Less Than 50 kW	kWh	7%	14%	0%	4%	0%	16%	28%	0%	14%	12%
General Service 50 to 999 kW	kW	1%	30%	57%	50%	53%	14%	40%	0%	33%	30%
General Service 1,000 to 4,999 kW	kW	0%	19%	40%	37%	44%	7%	(69%)	0%	26%	30%
Unmetered Scattered Load	kWh	1%	0%	0%	0%	0%	1%	0%	0%	0%	0%
Sentinel Lighting	kW	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Street Lighting	kW	21%	1%	2%	2%	3%	4%	(3%)	0%	1%	1%
Total		**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**0%**	**100%**	**100%**

Table 9-2.12 outlines the allocators used to determine the proposed regulatory asset rate rider by rate class for the Deferral and Variance Accounts.

Table 9-2.12 -Deferral/Variance Account Workform

		Amounts from Sheet 2	Allocator	Residential	General Service Less Than 50 kW	General Service 50 to 999 kW	General Service 1,000 to 4,999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
RSVA - Wholesale Market Service Charge	1580	(1,470,667)	kWh	(519,503)	(208,388)	(442,380)	(279,892)	(3,023)	(190)	(17,292)
RSVA - Retail Transmission Network Charge	1584	(244,701)	kWh	(86,439)	(34,673)	(73,607)	(46,571)	(503)	(32)	(2,877)
RSVA - Retail Transmission Connection Charge	1586	(436,592)	kWh	(154,223)	(61,863)	(131,328)	(83,091)	(897)	(56)	(5,133)
RSVA - Power (excluding Global Adjustment)	1588	(1,203,459)	kWh	(425,113)	(170,525)	(362,003)	(229,038)	(2,473)	(156)	(14,150)
RSVA - Power - Sub-account - Global Adjustment	1588	1,022,422	Non-RPP kWh	67,882	40,981	508,342	380,914	784	-	23,518
Recovery of Regulatory Asset Balances	1590	11	kWh	4	2	3	2	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	(38,086)	kWh	(13,454)	(5,397)	(11,456)	(7,248)	(78)	(5)	(448)
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	(118,956)	kWh	(42,020)	(16,856)	(35,782)	(22,639)	(244)	(15)	(1,399)
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	-	kWh	-	-	-	-	-	-	-
Total of Group 1 Accounts (excluding 1588 sub-account)		**(3,512,450)**		**(1,240,748)**	**(497,700)**	**(1,056,553)**	**(668,477)**	**(7,219)**	**(454)**	**(41,298)**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	121	# of Customers	108	11	1	0	0	0	0
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	474	# of Customers	424	42	5	0	1	1	0
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	52,292	# of Customers	46,826	4,693	535	21	59	155	3
Retail Cost Variance Account - Retail	1518	148,737	# of Customers	133,192	13,349	1,521	60	167	441	9
Misc. Deferred Debits	1525	1	# of Customers	1	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	137,892	# of Customers	123,480	12,376	1,410	55	155	408	8
Total of Group 2 Accounts		**339,516**		**304,031**	**30,472**	**3,472**	**136**	**380**	**1,006**	**20**
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	(92,434)	kWh	(32,652)	(13,098)	(27,804)	(17,592)	(190)	(12)	(1,087)
Total of Account 1562 and Account 1592		**(92,434)**		**(32,652)**	**(13,098)**	**(27,804)**	**(17,592)**	**(190)**	**(12)**	**(1,087)**
Special Purpose Charge Assessment Variance Account	1521	-		-	-	-	-	-	-	-
LRAM Variance Account **(Enter dollar amount for each class)**	1568	40,315		27,226	12,730	284	74	-	-	-
(Account 1568 - total amount allocated to classes)		40,315								
Variance		(0)								
Total Balance Allocated to each class (excluding 1588 sub-		**(3,225,053)**		**(942,143)**	**(467,596)**	**(1,080,602)**	**(685,859)**	**(7,028)**	**540**	**(42,365)**
Total Balance in Account 1588 - sub account		**1,022,422**		**67,882**	**40,981**	**508,342**	**380,914**	**784**	**-**	**23,518**
Total Balance Allocated to each class (including 1588 sub-		**(2,202,631)**		**(874,261)**	**(426,615)**	**(572,260)**	**(304,944)**	**(6,244)**	**540**	**(18,846)**

Calculation of Rate Riders

Table 9-2.13 summarizes the variables used to determine the proposed regulatory asset rate rider by rate class for the Group 1 and Group 2 accounts, excluding the Non-RPP rate rider for the 1588 Sub-Account Global Adjustment. The billing determinants are based on the 2011 Actuals and calculated for a one-year disposition period.

Table 9-2.13 - 2013 Deferral and Variance Account Rate Rider by Class

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1588 sub-account)	Rate Rider for Deferral/Variance Accounts
Residential	kWh	337,828,768	(942,143)	**(0.0028)**
General Service Less Than 50 kW	kWh	135,513,010	(467,596)	**(0.0035)**
General Service 50 to 999 kW	kW	741,149	(1,080,602)	**(1.4580)**
General Service 1,000 to 4,999 kW	kW	518,430	(685,859)	**(1.3230)**
Unmetered Scattered Load	kWh	1,965,510	(7,028)	**(0.0036)**
Sentinel Lighting	kW	337	540	**1.6015**
Street Lighting	kW	31,834	(42,365)	**(1.3308)**

Table 9-2.14 summarizes the variables used to determine the proposed non-RPP global adjustment rate rider by rate class. The billing determinants are based on the 2011 Actual non-RPP volume data and calculated for a one-year disposition period.

Table 9-2.14 - 2013 Non-RPP Global Adjustment Rate Rider by Class

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of RSVA - Power - Sub-	Rate Rider for RSVA - Power -
Residential	kWh	33,772,368	67,882	**0.0020**
General Service Less Than 50 kW	kWh	20,388,898	40,981	**0.0020**
General Service 50 to 999 kW	kW	651,576	508,342	**0.7802**
General Service 1,000 to 4,999 kW	kW	539,790	380,914	**0.7057**
Unmetered Scattered Load	kWh	389,969	784	**0.0020**
Sentinel Lighting	kW	-	-	**-**
Street Lighting	kW	33,125	23,518	**0.7100**

DEFERRAL AND VARIANCE ACCOUNTS REQUESTED

Thunder Bay Hydro is requesting certain variance and deferral accounts to track amounts that arise due to the change in capitalization policy in anticipation of changes required in accounting principles due to IFRS, notably the de-recognition of assets and post retirement employee benefits.

PP&E derecognition arises mainly from storm and accident damage requiring assets to be retired prematurely. Storm damage can vary greatly from year to year.

For the 2013 Test Year, Thunder Bay Hydro has not budgeted for losses due to the removal of infrastructure as a result of storm damage. This loss could fluctuate depending on the frequency and intensity of storms, and also the type and age of infrastructure assets affected.

Thunder Bay Hydro has not tracked this expense in the past, so it has very little data on which to base an estimate. The nature of this expense is such that it may vary greatly from one year to the next. Variations could be significant.

For these reasons, Thunder Bay Hydro requests a variance account to track the difference between actual PP&E derecognition costs and the amount that is approved in setting the 2013 rates, until its next rebasing.

Changes in actuarial valuations of the Post Retirement Employee Benefit (PREB) liability under CGAAP are amortized over a long period of time resulting in relatively small impacts and a more predictable annual expense. Under IFRS, changes in actuarial valuation are recognized much more quickly, often fully in the year, and can have a significant impact on the annual expense. As a result the annual expense can be much more volatile under IFRS. The nature of this expense is such that it may vary greatly from one year to the next. Due to this volatility, Thunder Bay Hydro requests a variance account to track the difference between actual PREB expense and the amount that is approved in setting the 2013 rates, until its next rebasing.

STRANDED METER COSTS

On July 5, 2012 Thunder Bay Hydro received its rate order from the Board in regards to its Smart Meter Disposal and Cost Recovery application EB-2012-0015. Smart meters had been 100% installed for Residential and General Service < 50 kW customers and costs incurred up to December 31, 2011 and the incremental revenue requirement for OM&A costs in 2012 were approved by the Board. A rate class specific Smart Meter Disposition Rate Rider ("SMDR") and Smart Meter Incremental Rate Rider ("SMIRR") were approved to be in effect for 22 months and 10 months, respectively. On page 13 of Thunder Bay Hydro's response to Board Staff interrogatory Question #12, the following was stated:

"Thunder Bay confirms that it is not seeking disposition of its stranded meters costs in this application but plans to do so in its 2013 Cost of Service Application. Thunder Bay estimates its NBV as at December 31, 2012 to be $1,567,441."

In this current 2013 Cost of Service Application, Thunder Bay Hydro requests to follow through with the above mentioned disposition, and seeks to dispose of its estimated NBV of its stranded assets as at December 31, 2012.

Table 9-3.1 provides a summary of the number of meters by rate class that were stranded and smart meters installed as at December 31, 2011.

Table 9-3.1: Meter count as at Dec. 31, 2011

	A	B	C = B - A	D = C / A
	Stranded Assets	Smart Meter Installs	Variance	% Variance
Residential	44,214	44,891	677	2%
GS < 50 kW	4,277	4,594	317	7%

With respect to the Filing Requirements Schedule Appendix 2-S, Thunder Bay Hydro responses as follows:

- Thunder Bay Hydro has transferred its stranded meter costs to the "sub-account Stranded Meter Costs" of Account 1555 (Scenario A).

- For financial and OEB reporting purposes, the stranded meter assets have remained in Account 1555 and were depreciated in 2009 through to 2012 to reduce the NBV through accumulated depreciation, recognizing that these meters are still in rate base and built into distribution rates.

- The forecasted NBV of the stranded meters as at December 31, 2012 is $1,567,441.

- The number of meters removed is found in the table above, which is compared to the number of smart meter installs provided in EB-2012-0015.

- The number of smart meter installs is higher for both rate classes compared to the number of meters stranded. The reasons for this variance are new services that occurred during the smart meter program (2009 to 2011) and replacement of problematic smart meters in the field.

- Thunder Bay Hydro notes that carrying charges have not been calculated on the balance above and did not sell and receive any proceeds or contributed capital for the stranded meters.

- Thunder Bay Hydro is proposing to recover the stranded meter assets over one year as set out in Table 9-3.2 and a detailed discussion of the calculation is found below

As per *Guideline G-2011-0001 Smart Meter Funding and Cost Recovery – Final Disposition December 15, 2011* on page 23, Thunder Bay Hydro proposes to dispose of the stranded meter costs based on the principles of cost causality and practicality and recovered through a rate rider for the applicable customer classes. Thunder Bay Hydro had set up work orders in its inventory system to capture the number of conventional meters that were being disposed of and their Net Book Values ("NBV") by rate class. The stranded asset balance forecasted as at December 31, 2012 has been allocated between the Residential and General Service < 50 kW rate classes by the percentages calculated by the work order totals mentioned above. Thunder Bay Hydro proposes to dispose of the stranded meter cost balance over a 12 month period

starting May 1, 2013 and using the 2013 forecasted number of customers to calculate the Stranded Asset Rate Rider ("SMRR") by rate class. Below is Table 9-3.2 summarizing the SMRR.

Table 9-3.2 – Rate Rider Calculation

Stranded Meter Costs				
Gross Book Value	$4,936,080			
Accumulated Depreciation	$3,368,639			
Net Book Value as at Dec. 31/12	$1,567,441			A
	Residential	**GS < 50 kW**	**Total**	
Number of Customers - 2013 Forecast	45,158	4,330	49,488	B
Porportion of Stranded NBV $	78%	22%	100%	C
Allocation of NBV to rate classes	$1,228,554	$338,887	$1,567,441	D = A * C
Proposed Disposition Period	12 months			E
SMRR per month	**$2.27**	**$6.52**		F = D / B / 12

GREEN ENERGY PLAN – FUNDING ADDER

Thunder Bay Hydro has submitted a basic Green Energy Plan to the OPA and has provided a copy in Exhibit 2, Appendix 2-B. The OPA provided a Letter of Communication which has been provided in Exhibit 2, Appendix 2-C. At the time of writing of this plan Thunder Bay Hydro estimated capital spending requirements of $387,154 in 2012 and $580,731 in 2013, of which $387,154 in 2013 is in regards to capital investment spending on "Renewable Enabling Improvements" ("REIs") was to be inputted to calculate the funding adder. Since filing the GEA Plan, the cost estimates have been revised slightly such that the total REIs to be deferred in 2013 is $375,786 for a unit cost of $62,631 (applicable for both 2012 and 2013 purchases).

Thunder Bay Hydro requests a funding adder to be included in its rates, based on the Incremental Revenue Requirement Calculation provided below in Table 9-4.1. An electronic version of this model has been provided as part of this application.

As discussed in its GEA Plan, Thunder Bay Hydro plans to purchase 6 reclosers estimated at $62,631 each (revised as discussed above), that are required as REIs for FIT renewable generation projects. With REIs, utilities can apply for the Direct Benefit calculation to its customers, with the balance designated for Provincial Rate Protection. Thunder Bay Hydro used the simplified method in which 6% of the costs are to be borne by its customers and 94% by the Province. Table 9-4.1 below shows the associated renewable capital investment.

Table 9-4.1 – Renewable Capital Investment

Cost		2012	2013	2014	2015	2016	
Renewable Connections Capital - Expansions	0	0	0	0	0	0	Total
Renewable Connections Capital - Renewable Enabling Improvements	0	-	375,786	-	-	-	$375,786
Feeder Automation Projects		0	0	$0	$0	$0	$0
TOTAL	0	-	375,786	$0	$0	$0	$375,786

		2012	2013	2014	2015	2016	
Renewable Connections Capital - Renewable Enabling Improvements							
Opening Capital Investment		$ -	$ -	$ 375,786	$ 375,786	$ 375,786	
Capital Investment		$ -	$ 375,786	$ -	$ -	$ -	
Closing Capital Investment		$ -	$ 375,786	$ 375,786	$ 375,786	$ 375,786	
Opening Accumulated Amortization		$ -	$ -	$ 4,697	$ 14,092	$ 23,487	
Amortization Year One	40 years	$ -	$ 4,697	$ -	$ -	$ -	40
Amortization Thereafter		$ -	$ -	$ 9,395	$ 9,395	$ 9,395	
Closing Accumulated Amortization		$ -	$ 4,697	$ 14,092	$ 23,487	$ 32,881	
Opening Net Fixed Assets		$ -	$ -	$ 371,089	$ 361,694	$ 352,299	
Closing Net Fixed Assets		$ -	$ 371,089	$ 361,694	$ 352,299	$ 342,905	
Average Net Fixed Assets		$ -	$ 185,544	$ 366,391	$ 356,997	$ 347,602	

Average Net Fixed Assets	Direct Benefit %	2012	2013	2014	2015	2016
Renewable Connections Capital - Expansions		$ -	$ -	$ -	$ -	$ -
Renewable Connections Capital - Renewable Enabling Improvements	6%	$ -	$ 185,544	$ 366,391	$ 356,997	$ 347,602
Feeder Automation Projects		$ -	$ -	$ -	$ -	$ -
		$ -	$ 185,544	$ 366,391	$ 356,997	$ 347,602
Direct Benefit		$ -	$ 11,133	$ 21,983	$ 21,420	$ 20,856
Direct Benefit %		0%	6%	6%	6%	6%
Weighted Average Direct Benefit %		0.00%	6.00%	6.00%	6.00%	6.00%

	2013
Qualify for Direct Benefit?	Yes
Funded by TBHEDI customers	$22,547
Funded by Province	$353,239
Gross Investment	$375,786
Direct Benefit %	6.0%

Based on the capital investment required, Thunder Bay hydro has estimated the incremental revenue requirement for these assets as $88,464 between 2012 and 2016. Table 9-4.2 Incremental Revenue Requirement & Funding Adder Calculation provides the details of this calculation. Thunder Bay Hydro has not estimated any incremental OM&A at this time; however, the incremental revenue calculation has been adjusted for PILS as calculated in Table 9-4.3. Thunder Bay Hydro proposes to recover $5,308 of this amount from its customers as a direct benefit through a fixed monthly funding adder of $0.0022 per customer for 4 years commencing May 1, 2013. Thunder Bay Hydro proposes to recover the remaining $83,156 through the Provincial Rate Protection and requests a funding adder from the IESO for $1,732 per month. Thunder Bay Hydro proposes to dispose of the balance in Account 1531 in its 2017 Cost of Service Application.

Table 9-4.2 Incremental Revenue Requirement & Funding Adder Calculation

	2012		2013		2014		2015		2016		
Net Fixed Assets		$ -		$185,544		$ 366,391		$356,997		$347,602	
OM&A	$ -		$ -		$ -		$ -		$ -		
WCA	15.0%	$ -	13.0%	$ -	13.0%	$ -	13.0%	$ -	13.0%	$ -	
Rate Base		$ -		$185,544		$ 366,391		$356,997		$347,602	
Deemed ST Debt	4%	$ -	4%	$ 7,422	4%	$ 14,656	4%	$ 14,280	4%	$ 13,904	
Deemed LT Debt	56%	$ -	56%	$103,905	56%	$ 205,179	56%	$199,918	56%	$194,657	
Deemed Equity	40%	$ -	40%	$ 74,218	40%	$ 146,557	40%	$142,799	40%	$139,041	
ST Interest	1.33%	$ -	2.08%	$ 154	2.08%	$ 305	2.08%	$ 297	2.08%	$ 289	
LT Interest	0.60%	$ -	1.89%	$ 1,964	1.89%	$ 3,878	1.89%	$ 3,778	1.89%	$ 3,679	
ROE	3.75%	$ -	7.00%	$ 5,195	7.00%	$ 10,259	7.00%	$ 9,996	7.00%	$ 9,733	
		$ -		$ 7,313		$ 14,442		$ 14,071		$ 13,701	
OM&A											
Amortization		$ -		$ 4,697		$ 9,395		$ 9,395		$ 9,395	
Grossed-up PILs		$ -		$ 814		$ 1,641		$ 1,750		$ 1,851	
Revenue Requirement		$ -		$ 12,824		$ 25,477		$ 25,216		$ 24,946	$ 88,464
Direct Benefit											
OM&A		$ -		$ -		$ -		$ -		$ -	
Capital		$ -		$ 12,824		$ 25,477		$ 25,216		$ 24,946	
Direct Benefit % on capital		0.00%		6.00%		6.00%		6.00%		6.00%	
Direct Benefit on capital		$ -		$ 769		$ 1,529		$ 1,513		$ 1,497	
Total Direct Benefit		$ -		$ 769		$ 1,529		$ 1,513		$ 1,497	$ 5,308
Total # of Customers (excl connections)		49,905		50,015		50,141		50,269		50,396	50,145
GEA Rate Adder		$ -		$ 0.0013		$ 0.0025		$ 0.0025		$ 0.0025	$ 0.0022
Provincial Rate Protection		$ -		$ 12,055		$ 23,949		$ 23,703		$ 23,449	$ 83,156
Monthly Adder Amount Paid by IESO		$ -		$ 1,005		$ 1,996		$ 1,975		$ 1,954	$ 1,732

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Table 9-4.3 PILS Calculation

	2012	2013	2014	2015	2016
INCOME TAX					
Net Income	-	5,195	10,259	9,996	9,733
Amortization	-	4,697	9,395	9,395	9,395
CCA	-	(7,516)	(14,731)	(14,142)	(13,576)
Change in taxable income	-	2,377	4,923	5,249	5,552
Tax Rate	26.25%	25.50%	25.00%	25.00%	25.00%
Income Taxes Payable	$ -	$ 606	$ 1,231	$ 1,312	$ 1,388
ONTARIO CAPITAL TAX					
Closing Net Fixed Assets	-	371,089	361,694	352,299	342,905
Less: Exemption	$ -	$ -	$ -	$ -	$ -
Deemed Taxable Capital	$ -	$ 371,089	$ 361,694	$ 352,299	$ 342,905
Ontario Capital Tax Rate	0.000%	0.000%	0.000%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ -	$ -	$ -	$ -
Gross Up					
	PILs Payable	PILs Payable	PILs Payable	PILs Payable	PILs Payable
Change in Income Taxes Payable	$ -	$ 606	$ 1,231	$ 1,312	$ 1,388
Change in OCT	$ -	$ -	$ -	$ -	$ -
PIL's	$ -	$ 606	$ 1,231	$ 1,312	$ 1,388
	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs	Grossed Up PILs
Change in Income Taxes Payable	$ -	$ 814	$ 1,641	$ 1,750	$ 1,851
Change in OCT	$ -	$ -	$ -	$ -	$ -

LRAM RECOVERY

Thunder Bay Hydro requests approval and recovery of historical Lost Revenue Adjustment Mechanism ("LRAM") amounts related to Conservation and Demand Management (CDM) activities in 2011. It is requested that these amounts be recovered through a rate rider over a one-year period beginning May 1, 2013. The total amount for recovery is a debit balance of $40,315, which includes carrying charges of $1,060. Please see ***Exhibit 4*** for additional detail on Thunder Bay Hydro's LRAM claim in its 2013 Cost of Service Application.